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ENVIRONMENTAL IMPACT STATEMENT

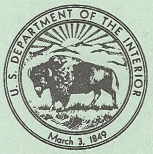
FOR THE

GEOTHERMAL LEASING PROGRAM

Revised Chapter IV, Sec. C
(Alternatives to Proposed Action)

Appendix G - Energy Alternatives

Appendix H - Proposed Unit Plan Regulations



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Introductory Note

This document contains the following:

1. A revised draft of the section on "Alternatives to Proposed Action" originally issued as part of the Draft Environmental Impact Statement for the Geothermal Leasing Program dated September 1971 and released October 6, 1971.
2. Appendix G, "Energy Alternatives," to the Draft Environmental Impact Statement for the Geothermal Leasing Program. This discusses alternative sources of energy in the event the leasing program is not implemented.
3. Appendix H, "Proposed Unit Plan Regulations for Geothermal Steam and Associated Geothermal Resources". These regulations are also being published in the Federal Register as proposed rule-making under Title 30, Code of Federal Regulations. After public review and comment, they will be adopted as final rule-making concurrently with the Leasing and Operating Regulations for Geothermal Resources.

A final environmental impact statement will be prepared in compliance with Section 102(2)(c) of the National Environmental Policy Act after the appropriate period for receipt of comment on this document.

Introduction

The following "Alternatives to Proposed Action" are revisions of the alternatives presented on pages 40-41 of the Draft Environmental Impact Statement for the Geothermal Leasing Program dated September, 1971 and released by the Department of the Interior on October 6, 1971. These revisions consider the impact of energy alternatives which would arise if one of the administrative alternatives to the proposed action was adopted.

C. ALTERNATIVES TO PROPOSED ACTION

(1) The Secretary could decline to promulgate the proposed geothermal leasing and operating regulations (Appendixes A and B). This would mean that there would be no direct environmental impact on Federal lands. To adopt this alternative the Secretary would have to decide that on balance the development of geothermal resources is environmentally unacceptable. Such a decision would be contrary to the Congressional directive in the Geothermal policy to encourage private investors to explore for and develop the geothermal steam and associated geothermal resources underlying the public lands of the United States.

(2) The Secretary could postpone geothermal leasing pending further study of the environmental impact. This would mean that, on a short term basis, there would be no direct environmental impact on Federal lands. Considerable additional data and information, which would be helpful in further evaluating the environmental effects of geothermal resource development and production, are expected to be generated from exploratory drilling activities under geothermal leases. Such information would not be available for evaluation while geothermal leasing is being postponed.

(3) The Secretary could decline to issue any leases to develop Federally owned geothermal resources. This would mean that there would be no direct environmental impact from geothermal development on Federal lands. Development of non-Federal geothermal resources would not be affected by this type of action and it would be expected to continue at an expanded rate. Where such private development overlies the same pool or geothermal source as that located on Federal lands, there could be a loss of proper utilization or a drainage of the energy of Federal land resources due to the inability of the government to regulate the development of the geothermal resources under its lands. At the present time, the only operating geothermal development in the United States is situated on private lands. Adjacent Federal lands are not developed thereby possibly preventing maximum conservation and utilization of the resource.

Under this alternative, knowledge of the environmental effects of geothermal development could not be expanded to the same degree as when study is directed to the nature and characteristics of given geothermal reservoirs as disclosed by actual exploration. The design of more sophisticated controls for the expected environmental impact of such development would, in all probability, be affected similarly. In addition, under alternatives (1) and (3), and, depending upon the length of any postponement, under (2), energy needs, which might otherwise be supplied by geothermal development on Federal lands, would have to be met by utilizing other energy sources, e.g., fossil fuel or nuclear plants, which could have greater impact on the environment than would geothermal development on Federal lands.

Summary Review of Geothermal Development

The development of geothermal and associated geothermal resources involves the harnessing of the natural heat energy sources in the earth for the generation of electric power, and the production of commercially valuable by-products.

The uses of geothermal steam as a source of energy is still in large part in the investigative stages. These energy sources are not expected to be panacea for the Nation's electrical power shortages, but they could have a part in assisting localized alleviations. However, it will take several years of exploration and research before meaningful quantities of power are produced.

Numerous studies of national energy demand have been made in recent years and all predict a rapidly increasing demand. Two of the most authoritative studies, which will be relied on subsequently in this statement are "United States Energy - A Summary Review" issued by the Department of the Interior, January 1972, and "U. S. Energy Outlook," an appraisal made by the National Petroleum Council at the request of the Secretary of the Interior, issued in November 1971. In the former report the Department estimates that energy demand in the United States will increase from 68,810 trillion Btu in 1970 to 191,556 trillion Btu by 2000.

The portion of the total energy demand attributable to electric generation by utilities would be 76,000-85,000 trillion Btu, depending upon future developments in power generation. Of this gross, some 32,000-36,000 trillion Btu would be represented by electrical distribution. The difference in these figures represents inherent in-

efficiencies in electric power generation and distribution.

In meeting future energy demand, the Nation must use many available sources of energy--coal, gas, oil, hydroelectric, and nuclear among the more important--and no one source is an exclusive alternative to any or all the other sources. In this context, geothermal energy would hopefully be a feasible means of supplementing other forms of electric power generation on a local scale. Under present technological and economic conditions, however, geothermal cannot be expected to substitute for other forms of electric generation. Indeed, as of spring 1972, the total world geothermal generating capacity was less than 1000 megawatts (Mw), the equivalent of a single medium-sized fossil fuel or nuclear power plant. Even under favorable assumptions, "United States Energy" estimates that geothermal energy will comprise less than 1% of the national power capacity through the year 2000.

In the following discussion and in the "Energy Alternatives" section (Appendix G) emphasis is placed on the potential for geothermal development in the western states because the geothermal resources are generally restricted to this area and the power developed presumably would be used in the western states. Three levels of development are considered: (1) the present electrical generating capacity, (2) the potential capacity at the single existing proven field, and (3) the projected development through the year 2000 as forecast by the National Petroleum Council (1972).

At present the prospects for geothermal power generation are most promising in California, where favorable geologic conditions coincide with a heavy demand for electrical generating capacity. The present commercial development at the Geysers in northern

California, compares favorably in cost with competing sources of power in that area and has the added advantage of appearing less environmentally detrimental as compared to fossil fuel or nuclear power, the principal alternatives (see Appendix G). Capacity as of spring 1972 is 192 Mw, and an additional 110 Mw is scheduled for completion late in 1972. Present commitments call for addition of 110 Mw in 1973 and 1974 to reach a total installed capacity of 522 Mw (Barton, 1972). Beyond 1974, the Pacific Gas and Electric Co. has tentatively scheduled installation of at least 100 Mw of new capacity per year depending upon availability of steam. Estimated ultimate capacity of the Geysers field is 1,000 to 2,000 Mw, but this remains to be proven. Thus, it can be seen that the Geysers development can be considered as the alternative to a comparable level of new fossil fuel or nuclear generating capacity in the PG and E system - perhaps one plant.

Elsewhere in California the most favorable areas for prospecting are the Imperial Valley Area and the Mono Lake - Long Valley Area, both described in appendices to the Draft Environmental Impact Statement. Test drilling in both areas suggests promising prospects for commercial power development, but in both areas the handling and disposal of large volumes of water pose significant technical, economic and environmental problems that must be resolved before large-scale power development can proceed. The present status is that feasibility of commercial power generation still remains to be demonstrated except at the Geysers.

Geothermal power is not expected to make a significant contribution to the national power demand at least until the year 2000. On the regional scale, it is economically attractive at a few locations, chiefly in California where occurrence of the resource favors development; however, the present reasonably well demonstrated potential of 1000-2000 Mw capacity at the Geysers is not expected to comprise more than 5% of Pacific Gas and Electric Company's total system generating capacity.

The 1970 energy consumption by electric utilities within PAD District V [1/] is estimated to be 2,705 trillion Btu (NPC, 1971) of which roughly 800 trillion Btu will reappear for electrical distribution. This consumption is expected to grow to 5,477 trillion Btu consumption by electric utilities by 1980, of which some 1,600 trillion Btu would reappear for electricial distribution. When the projected 1,000-2,000 Mw capacity of the Geysers Field is expressed in Btu (27 to 54 trillion Btu) it can be seen that as of 1980 geothermal generation there will comprise only 1.7 to 3.4 percent of the regional total for PAD District V.

A detailed discussion of the various energy alternatives is contained in Appendix G hereto. In general a given capacity of geothermal generation has the least adverse environmental impact as compared to alternative sources because no fuel is being mined, transported, handled, or consumed. Power plants will be located at the site of the geothermal source and the environmental impact of the sites would be local in scale. On the other hand geothermal generation has the unfavorable

1/ Petroleum Administration for Defense District V comprises the states Arizona, California, Nevada, Oregon, Washington, Alaska, and Hawaii.

aspect of greater water consumption per unit of electricity because of its lower thermal efficiency inherent in present plant design. The environmental impacts of noise and emission of noxious gases appear to be controllable with presently available technology. From the environmental standpoint, nuclear power would appear to be the most acceptable alternative to geothermal, but it is handicapped by the very unlikely, but nevertheless possible hazard of a disastrous nuclear accident, and by health and safety considerations associated with spent fuel transportation and reprocessing. While waste thermal discharge at nuclear plants exceeds that of fossil-fuel plants it is significantly lower than of geothermal plants in current use; thus, for a comparable capacity the water consumption by presently designed geothermal plants is greater than either nuclear or fossil fuel generation.

Emphasis has been placed in the foregoing on the utilization of geothermal energy to produce electric power as an alternative to other means of generating power; this is because the resource is heat energy, and production of electric power is simply the form of energy most readily usable by the public and industry. Other means of utilizing geothermal energy have been proposed, and even been implemented in special situations. These include the use of the thermal energy for extraction of minerals from brines, direct use of thermal waters for space heating and industrial processing, and recreational and therapeutic use of thermal waters. However, under technical and economic constraints that currently apply there is little commercial interest in leasing of Federal lands for these purposes. These uses are not energy alternatives as such but are mentioned here for the purpose of placing the discussions on electric power in their proper context. A more

complete discussion of these other uses is contained in the Draft Environmental Statement. Therefore, these uses are not treated in this discussion of alternatives to the proposed leasing program, but where these interests or others are recognized and leasing of Federal lands would be involved, the environmental impact would then be assessed.

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ENERGY ALTERNATIVES

Appendix G

To

DRAFT ENVIRONMENTAL IMPACT STATEMENT

FOR THE

GEOTHERMAL LEASING PROGRAM

in compliance with

Section 102 (2) (c) of the National Environmental

Policy Act of 1969

Prepared by

U. S. Department of the Interior

May 1972

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Introduction

The Draft Environmental Impact Statement for the Geothermal Leasing Program, issued October 6, 1971, by the Department of the Interior, in compliance with the National Environmental Policy Act of 1969, discussed alternative administrative actions to implementation of the proposed leasing program that were available to the Secretary of the Interior.

This appendix of energy alternatives to the geothermal leasing program for meeting the Nation's energy demands provides additional information regarding alternative energy sources.

Forecasting the potential for geothermal power development is uncertain at best because such development depends largely on unknown factors, principally those concerning the availability and extent of geothermal reservoirs, the cost of winning steam and generating power from hot water systems, and the future costs of competing methods of generating power. Accordingly, in order to put the alternatives in proper prospective, this report will consider three rather subjective levels of geothermal capacity for the electric-power market: (1) a present capacity of 192 megawatts (Mw) all located on non-Federal lands in the Geysers Field in Sonoma and Lake Counties, California; (2) a probable ultimate development in the Geysers area ranging from 1,000 to 2,000 Mw depending upon future exploration results and involving mainly private land, but including about 10 to 15 percent Federal ownership; and (3) a development of 7,000 to 20,000 Mw capacity by 1985 as recently projected by the New Energy Forms Task Group of the National Petroleum Council Committee on U. S. Energy Outlook (National Petroleum Council, 1972).

Examination of the potential for geothermal development on the public lands (Godwin and others, 1971) indicates that such potential is limited generally to the Western States. Furthermore, commercial interest in development is largely restricted to California and Nevada, and to Oregon and Washington to a lesser degree. Thus, the role of geothermal development in helping to meet national energy needs and its relationship to alternative means of supplying energy will be discussed primarily in the context of the West Region as defined by the Federal Power Commission, which includes the areas of commercial interest and foreseeable geothermal development on Federal lands.[1/] The accompanying table presents projections of electric-power demand and fuel use in the West Region for several periods through 1990.

Consideration of alternatives to the three levels of generating capacity described above indicates the following: If the present 192 Mw capacity at the Geysers Field were removed from the Pacific Gas and Electric system, the company would be obliged to replace this with comparable generating capacity of a different form. Under present economic constraints this would require increasing capacity by 192 Mw at existing plants, by decreasing reserve capacity, or by providing new generating capacity in that amount, probably by an addition to existing facilities. Such additional capacity would most likely take the form of oil or oil and gas fueled steam generation with its attendant environmental hazards of air pollution and thermal waste discharge. The location and specific environmental impact of the substitute generating capacity are indeterminate and would depend upon management decisions by private companies.

1/ The States of California, Oregon, Washington, Nevada, Idaho, Utah, Colorado, Arizona, New Mexico, and parts of Texas, Oklahoma, Kansas, Nebraska, Wyoming, and Montana; essentially the Mountain and Pacific States.

SUMMARY OF 1968 WEST REGION SURVEY OF FUELS [1/]
FOR ELECTRIC GENERATION-NATIONAL POWER SURVEY

	1965		1970		1980		1990	
	Quantity	% of Total	Quantity	% of Total	Quantity	% of Total	Quantity	% of Total
1. Population (Thousands)	31,006	-	34,650	-	43,400	-	54,241	-
2. Total Energy Use (10^{12} Btu)	8,904	100	10,721	100	15,585	100	22,608	100
% Consumed for Electric Generation	-	25	-	29	-	39	-	52
% Consumed for Thermal Elec. Generation	-	11	-	14	-	28	-	43
3. Total Elec. Utility Generation (10^9kwh)	209	100	308	100	631	100	1,205	100
Thermal Elec. Utility Generation (10^9kwh)	89	43	149	48	447	71	1,007	84
4. Fuel Use for Thermal Elec. Utility Generation (Equivalent Trillion Btu's)	924	100	1,469	100	4,228	100	9,767	100
(a) Coal (Thousand short tons)	7,729	14	15,496	20	59,264	28	93,536	21
(b) Natural Gas (Billion cubic feet)	628	72	855	63	685	17	724	8
(c) Uranium (Short tons U_3O_8)	14	1	1,027	5	8,175	47	15,640	67
(d) Thorium (Short tons ThO_2)	-	-	-	-	3	-	100	1
(e) Oil, No. 6 (Thousand bbl.)	18,555	13	7,705	4	1,400	-	1,425	-
(f) Oil, Low Sulfur (Thousand bbl.)	-	-	16,000	8	49,375	8	46,000	3
5. Average Heat Rate, Fossil Fueled Thermal Elec. Generation (Btu/kwh)	10,412	-	9,865	-	9,471	-	9,718	-
6. Fuel Price Estimates (¢/M^2Btu), excluding Transmission								
(a) Coal	16		15		16		17	
(b) Natural Gas	30		31		34		36	
(c) Uranium	26		20		15		13	
(d) Thorium	-		20		15		13	
(e) Oil, No. 6	32		32		28		32	
(f) Oil, Low Sulfur	-		41		42		44	

7. Fuel Reserves

(a) Coal (Million Short Tons, 1968)	263,230
(b) Natural Gas (Billion Cubic Ft., 1966)	30,464
(c) Uranium (Short Tons U_3O_8, 1968)	148,000
(d) Thorium (Short Tons ThO_2, 1968)	100,000
(e) Oil, No. 6 (Million bbl., 1966) (15% of Crude & Shale Oil Reserves)	101,026
(f) Low Sulfur Oil (Million bbl.)	-

1/ From "The future of Power in the West Region 1970-1980-1990" West Regional Advisory Committee Report to the Federal Power Commission 1969.

If the estimated level of 1,000 to 2,000 Mw is not achieved by development at the Geysers Field, the Pacific Gas and Electric Company likewise would be obliged to generate the equivalent power by other means. This level of power generation would most likely require new construction of oil fired or nuclear generating capacity. In the oil-fired case similar environmental considerations to those cited above would also apply, mainly increased air pollution, thermal waste discharge and the potential for oil spills. In the case of a nuclear power plant the main environmental hazard would be thermal waste discharge. With either source this capacity may normally be provided at a single plant with a limited local environmental impact. As in the previous case, the location of and the specific type and severity of environmental impact are indeterminate, depending upon management decisions.

The higher estimate of 7,000 to 20,000 Mw capacity envisioned for ultimate geothermal development entails a larger area and additional options for consideration. The West Region, where the principal geothermal development is expected, includes also the Lower Colorado River basin, which is the site of several large coal-fired steam electric plants. Several of the existing plants and projected new plants feed power into the power network that serves southern California and have interties to other parts of the West that are considered likely sites for geothermal power development and marketing. Thus, at this level of development, coal-fired steam generation is a viable alternative to geothermal power, but it too has certain environmental risks. The same level of generation could also be met by construction of additional oil-fired or nuclear plants closer to the power markets involved, but with environmental consequences similar to those already described. In any event the 7,000 to 20,000 Mw capacity is well within

estimated growth of electric demand in the West Region through 1990 and if geothermal development is not realized the equivalent requirement will have to be met by other forms of generation. New plants under construction, particularly coal and nuclear, commonly are designed for about 2,000 Mw capacity, so it can be seen that 4 to 10 such plants could substitute for the estimated 7,000 to 20,000 Mw potential geothermal development. As in the previous cases the specific locations and environmental impacts are indeterminate at this time. The general form of impacts of nuclear and oil-fired plants would be as described above. Coal-fired plants have a similar impact to oil-fired plants at the point of use; however, they present the added impacts associated with coal mining, transport of coal to the power plants, and disposal of solid waste. Such impacts resulting from development of coal-fired plants in the Colorado basin are currently being evaluated by the Department of the Interior as part of the Southwest Energy Study. Several parts of that study have been released to the public and the remaining parts are scheduled for release in April 1972.

In comparison with regard to environmental impact; a given capacity of geothermal generation has less adverse environmental impact as compared to these alternative sources because no fuel is handled or consumed. On the other hand it has the unfavorable aspect of greater water consumption per unit of electricity because of its inherently lower thermal efficiency. The environmental impacts of noise and emission of noxious gases appear to be controllable with presently available technology, and it is proposed that these will be controlled under the leasing program undertaken following the adoption of the leasing and operating regulations. From the environmental standpoint, nuclear power would appear to be the most

acceptable alternative to geothermal, but it is handicapped by the very unlikely, but nevertheless possible hazard of disastrous nuclear accident, and by health and safety considerations associated with spent fuel transportation and reprocessing.

The following sections discuss the various energy sources which could substitute for geothermal power and their environmental impacts with special reference to the West region.

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Coal

An abundant supply of low-sulfur bituminous and sub-bituminous coal and lignite occurring in the West Region is a substitutable alternative for geothermal energy. Much of the coal resources lie in or adjacent to the West Region and could serve as sources for electrical energy production in this area, either through transportation of the coal to power plants or through transmission of electrical energy from mine-mouth power plants.

Reserves of low-sulfur coal in the Rocky Mountain States were estimated to be 874 billion short tons as of January 1967 (Averitt, 1969, p. 33). 188 billion short tons are in beds usually 10 feet or more thick, and less than 1,000 feet below the surface. The recoverable resources are about 444 billion short tons to a depth of 3,000 feet and 94 billion short tons to a depth of 1,000 feet. Approximately 45 billion short tons of the recoverable resources could be extracted by open pit mining methods. At present, very large open pit coal mines may produce 5 million short tons of coal per year per mine. Very large underground mines may produce 2 million short tons per year per mine.

If coal were to be used as a substitute for geothermal energy in the generation of electric power, it is estimated that an additional 2,000 tons of coal per day would be required to replace the existing 192 Mw Geysers generating capacity. This level could be reached by expanding existing coal-fired power plants in the West Region. An estimated 10,000 to 21,000 tons of coal per day would be required to replace the 1,000 to 2,000 Mw power potential of the Geysers and an estimated 72,000 to 206,000 tons of coal per day would be required to replace the estimated

ultimate 7,000 to 20,000 Mw geothermal potential. The replacement impact of coal-fired power plants would thus range from a modest scale-up of existing facilities to the development of 35 to 40 large underground coal mines or the development of 25 very large surface coal mines or various combinations of both types of mining. Associated power plants to convert the 75,000,000 tons of coal per year to electrical energy to meet the 20,000 Mw geothermal potential would also have to be constructed. Coal production of this magnitude could have a severe impact on the environment.

In addition to the environmental impacts of coal production, there are the health and safety considerations relating to underground and surface coal miners. During 1969, there were 155 fatal and 8,139 non-fatal accidents in the Nation's underground coal mines and 28 fatal and 942 non-fatal accidents in surface coal mines. Surface coal mines produced approximately 35.2 percent of the 1969 United States coal output of 560 million tons. It is expected that surface production of coal will increase to about 47 percent of the total 1971 coal output. Although surface mining has less impact on the health and safety of the mine workers, surface mining may result in a greater environmental impact than underground mining. Any trade-off between health and safety considerations and environmental impacts must be carefully weighed in determining whether surface or underground mining is more or less desirable.

Although it is not possible to define all of the environmental impacts that increased coal production may have without specific site locations and information on the interactions between power plants, air, and water quality, it is possible to point out the general environmental considerations of increased coal production and utilization.

UNDERGROUND MINING

Subsidence of the ground surface is common above many abandoned and some active coal mines. The amount of subsidence relates to the mining method employed, the amount of coal removed, the thickness of the coal bed, and the composition and strength of rocks overlying the coal. Subsidence of large areas may destroy man-made structures and disrupt the ground water flow regime, cut off surface and subsurface water recharge, adversely affect the quality of underground and surface waters, redirect the planned drainage of a mine, disrupt surface drainage, and in periods of heavy rainfall localize flooding. It also, in some localities, causes landslides, and minor earthquakes.

The most successful method of preventing or alleviating surface subsidence problems is to plan mining so that more pillars are left untouched. Unfortunately, this procedure results in less coal recovery. Much additional research is needed to develop methods of underground mining which will minimize subsidence of the surface.

Ground and surface waters entering active underground mine workings are normally pumped to the surface for disposal. Because of the low sulfur content of most Rocky Mountain coals, it is uncertain whether acid-mine water would be a problem in areas of large-scale mining and/or above average precipitation. If acid-mine water problems should develop, it is likely that the modern treatment methods employed in the coal fields of the Eastern United States could be implemented to abate acid water impacts. The large volumes of sludge resulting from such treatment could be emplaced either in abandoned mine workings or in protected surface mine waste disposal areas. Commonly acid-mine water drains from abandoned mines and workings. This type of effluent discharge can be prevented by locating mine entries at elevations above the prevailing drainage level, by sealing abandoned underground entries, and by emplacing dams at critical points in abandoned underground entries and haulageways.

In most coal producing areas, mining and processing wastes contribute large volumes of sediment to nearby streams, are sources of acid drainage and, where waste piles are burning, are sources of air pollution. The most commonly used technique of preventing widespread scattering of mining and processing wastes is to compact the waste in layers, followed by sealing with incombustible soil, after which vegetation is established to prevent infiltration of surface water and to minimize erosion.

An alternative to surface disposal of mine and coal processing waste is to return it to abandoned underground mine workings. This is currently being done to control surface subsidence in mined areas in the Eastern States in compliance with restoration provisions of the Appalachian Regional Development Act of 1965, as amended. (Kenahan and Flint, Bu. Mines I.C. 8529, p. 24)

Dust from mine access roads, coal handling, and processing can be alleviated. Road dust can be minimized by hard surfacing, or through abatement techniques, such as oiling or chemical treatment of the road surface. Dust from coal handling and processing can be abated by spray treatment at transfer points and by enclosing coal handling and processing structures. Dusting problems in live coal storage piles can be reduced by water sprays or oiling; dead storage piles can be sealed with asphaltic or chemical materials, but all of this costs money, and points to geothermal steam as a viable alternative.

Underground mining results in less noticeable noise and vibration than surface mining, and the surface environmental effects from drilling, blasting, and spills and leaks are minimal. Also modifications of the habitat, alteration of ground cover, and alteration of surface drainage systems would only occur in a limited sense.

Most pollution sources can be eliminated by sealing and revegetating waste disposal areas; sealing abandoned mine openings; dismantling and removing abandoned mine buildings and structures; and scoring, fertilizing, and revegetating areas formerly occupied by buildings and structures, mine roads, and supply storage areas. Consideration should also be given to

flushing all wastes and plant refuse into underground mine voids to remove sources of surface pollutants and to reduce possible surface subsidence. Such flushing of wastes could have either beneficial or detrimental effects on the ground water flow and surface drainage, depending upon local conditions.

SURFACE MINING

Open pit mining disturbs considerably more surface acreage than underground mining. Underground mining operations, however, because of lower recovery per unit of area, actually disturb more acreage in three dimensions than an open pit mine producing a similar tonnage. Unfortunately, the full magnitudes of underground disturbances generally are not understood by the public. As of 1967, it is reported that open pit coal mines were responsible for 41 percent of the land disturbed by surface mining in the United States (U. S. Department of the Interior, 1967, p. 53-54).

Climatic conditions are extremely important in considering the rehabilitation, reseeding, and revegetation of mined lands in the Rocky Mountain States. Obviously, without proper moisture, the reseeding of reclaimed lands would serve little purpose and erosion processes would soon destroy the contour of the rehabilitated lands.

Disruption of the land surface by open pit mining would, unless proper precautionary measures are implemented, have adverse impacts on all vegetation, forestry, grazing, crops, birds, land animals, endangered species, habitat, water supplies, and water quality, all of which would limit the enjoyment of hunting, fishing, and allied leisure time activities in addition to affecting scenic vistas and open spaces. Furthermore,

nearby agricultural, residential, commercial, and industrial activities may be affected by adverse environmental impacts propagated beyond the area of mining.

Few coal deposits are free of contaminants; therefore, it can be assumed that under ideal conditions, a 5-percent washer loss would occur. The problem would not be major for surface mines in that the pits from which the coal would be extracted, could receive this material. Ultimately, the mine pits would be backfilled, the spoil banks topped off or leveled, the highwalls backsloped, the top soil replaced, and the area reseeded.

Other short-term problems related to surface coal mining are acid mine water developing in the open pits, in spoil piles, and in mine processing waste; silt eroding from the pits, processing waste and spoil piles; and dust blowing from the pits, spoil piles, truck haulage roads, railroad cars, mine processing plant, and processing waste piles. Each of these problems can be handled effectively by requiring the mining companies to observe environmental regulations.

Proper supervision within the scope of adequate environmental regulations could result in mined lands being returned to "as good or better than found conditions," in that some restored lands could lend themselves to recreational sites, lake impoundments for boating and fishing, picnic areas, and eventually could promote resort facilities.

The end use to which surface-mined lands can be reclaimed concurrent with mining is limited only by the capacities of men operating within prevailing geologic, technologic, and economic restraints.

Land use committed to truck haulage is the largest of any of the coal transportation systems. In the Rocky Mountain States, the presence and movement of large numbers of trucks in open areas may be aesthetically objectionable to the public, especially if the haulage roads are near public use areas.

Secondary environmental impacts from truck transportation arise from improper disposal of tires, expended oil, and used parts. These items can be disposed of in open cuts of surface mines and then buried with reclaimed spoil and revegetated. In addition, special disposal pits can be excavated at underground mining operations where these items can be buried and the area revegetated. Depending on economics of the particular mining operation, a reasonable alternative would be to recycle these items.

Rail transportation systems using diesel locomotives are sources of air and noise pollutants from engine exhaust systems. Effective maintenance of engine combustion systems and efficient mufflers can reduce the air and noise pollution levels from these systems. Coal dust lost in transit can be reduced by using partially covered hoppers or by oiling the coal during loading. Dusting during loading and unloading can be reduced with a combination of dust suppression sprays and enclosed chutes or bins.

The right-of-way for a railroad constitutes a permanent commitment of the land surface to this use making it unavailable for other uses. Free travel of vehicles, people and animals across the committed area is restricted; however, the potential for collisions with trains does exist.

In the open or scenic areas of the Rocky Mountain States, railroad rights-of-way may be considered as aesthetic intrusions, especially if

large trestles, overpasses, or cut and fill areas are required. Cut and fill areas can be constructed with gentle slopes and revegetated, and borrow areas can be reclaimed as mentioned in conjunction with truck transportation systems. The visual impact of trestles, overpasses, and other appurtenant structures can be minimized with effective combinations of eye-pleasing designs and unobtrusive colors.

Conveyor system installations likewise constitute a permanent commitment of the land surface and restrict free movement of vehicles, people, and animals. The right-of-way width is less than that required for truck or railroad transportation systems. Uncovered or partly covered conveyors allow loss of dust in transit because of exposure to winds. Uncovered transfer points also are a potential source of dust when suppression devices are not provided. Open, or partly covered conveyors, constitute a safety hazard to persons or animals when a support structure is installed close to the ground. Conveyor systems can be fenced or completely enclosed to eliminate dusting and safety hazards to humans and animals.

Conveyor support structures, either frame or suspension type, as well as the conveyors, are obvious visual intrusions, especially at points where the conveyor crosses deep drainage systems. Color treatment and aesthetic design of support structures, enclosures, and transfer structures would lessen this impact.

The principal impacts of coal slurry pipeline systems are: the permanent commitment of land; providing an adequate water supply; and waste water disposal. Large quantities of water, at the rate of one ton of water per ton of coal, are required to transport coal in the Black Mesa, Arizona,

Pipeline (Arnold, 1969, p. 8). In water deficient areas, this method may not be an efficient transportation alternative, particularly where the water must be supplied by deep wells which, when pumped, could have a draw-down effect on shallower wells that supply people or livestock. Additionally, water disposal problems at the terminus of a pipeline could have an impact on water quality if not properly contained or when not economically feasible to recycle the water for transportation purposes. Coal slurry destined for power, gasification, or liquefaction plants could be dewatered, the "spent" water used for cooling tower makeup, ash handling, and/or evaporated in disposal ponds. The Mohave generating station in Nevada is utilizing water from the Black Mesa Pipeline in this manner.

The disposal of solids and water removed from sections of a plugged pipeline could cause environmental impacts. Holding ponds, equal in capacity to the upstream pipeline, could be provided at pumping stations and at the coal slurry preparation plant for disposal of removed plugs. The water could be evaporated and the coal may be left in the impoundment unless provisions are made for recovery. Compaction and sealing can prevent spontaneous ignition, erosion, and accompany siltation of the coal left in impoundments. The surface of the impoundment can be revegetated with indigenous or non-native plants to inhibit erosion of the seal.

WASTE DISPOSAL

Large volumes of waste are generated during coal mining and processing. The volume of mine waste depends on the type and characteristics of top and bottom strata, the continuity of a coal bed, the existence of fault zones, and the tonnage of county rock that must be mined. The type and

volume of waste discarded during coal processing depends upon the specifications for which the coal is being prepared, characteristics and amounts of impurities in the coal bed being mined, and the efficiency and type of coal processing equipment.

Uncontrolled disposal of coal mining and processing wastes, especially those containing carbon and trace amounts of sulfur, constitute a source of land, water, and air pollutants.

Water flowing over waste disposal areas commonly transports silt and leached minerals to adjacent land and surface water drainage areas. In addition, dust-size particles may be transported by winds to contaminate adjacent land and water resources. If a waste pile containing large amounts of carbon ignites, noxious gases enter the atmosphere where they are hazardous to plants, animals, people and property. (McNay, 1971, p. 8).

Waste disposal areas require a commitment of land resources. Furthermore, if poorly constructed and uncontrolled, these waste areas present an unattractive appearance to viewers.

Slides and slump failures commonly occur where waste is deposited on slopes and where an improper combination of moisture and clay minerals in the topsoil or in the waste act as lubricants. In such unstable conditions, large quantities of waste can move downslope and have adverse effects on land and water resources as well as being safety hazards to plants, animals, and people.

Should fine coal cleaning be included in the preparation processes for Rocky Mountian coals, the discarded fine waste would probably be deposited in slurry impoundments where the water would either be decanted for recycling to the preparation plant or allowed to evaporate. Poorly

MINE MOUTH POWER PLANTS

A recent development at several of the western coal mines is the establishment of the power plant at the mine mouth. The adjacent development of mine and power plant greatly reduces the cost and environmental impact of any coal transportation system and allows ash from the power plant to be readily returned to the mine for disposal. Burial of the ash between the spoil banks and in the pit cuts at surface mines reduces the possibility of water or wind transport of the ash and subsequent environmental damage. Mine mouth power plants associated with underground mines require surface disposal areas for the ash. Transmission lines from the mine mouth plants may have an impact on the environment depending upon routings and the availability of existing transmission lines with reserve capability for handling the additional plant output.

Location of the power plant at the mine mouth depends upon several critical factors. Water for cooling purposes must be available in sufficient quantities at the plant site or within a reasonable distance of the power plant to allow economical pumping operations to bring the water to the plant. Pipeline routings to bring water to the power plant can have an environmental impact which must be considered during the planning stages. The coal supply at the mine must be of sufficient quality and quantity to supply the power plant over its projected operating life. Insufficient coal supplies will require coal to be shipped to the power plant if the local supplies are exhausted at an earlier date than expected. Environmental considerations relating to transmission line routings, plant siting, combustion byproducts, water usage, surface

storage of ash at underground mines, and other such factors must be favorable to allow development.

COAL TRANSPORTATION

Four systems of transporting coal would be available in the Rocky Mountain States for moving coal from a mine to a point of utilization. These systems would be: trucks, railroads, conveyors, and coal slurry pipelines. A fifth system, water transportation, may be discounted because of the lack of navigable waterways. Each system has advantages that would make it economically attractive for transporting coal to a point of utilization. Selection of a system would be strongly influenced by the distance to a utilization plant.

The major adverse environmental impacts of these transportation systems are air and noise pollution, safety, the amount of land required for rights-of-way, trash disposal, water quality and aesthetics.

Air pollution sources are exhaust emissions, road dust, and coal dust. The level of adverse exhaust emissions can be reduced through efficient engine maintenance; road dust can be reduced by haul-road surface treatment such as hard surfacing, oiling, or applying water-chemical solutions; and coal dust can be reduced by truck covers and spraying. Although mufflers can reduce the level of noise pollution, truck haulage, because of the large number of noise sources and frequent trips, is commonly recognized as the noisiest system of transportation.

Collisions between trucks, other vehicles, and animals can occur but do not normally constitute a serious public hazard because haulage roads generally are confined to mine property.

designed impoundment dikes in the past have permitted percolating leachate water to enter downslope surface water drainage areas.

In addition, construction of impoundments on underlying pervious bedrock commonly results in infiltration of the ground water table by mineralized water or in percolation of such water through the base of dikes to enter downstream surface water drainage systems where these types of leakage commonly affect aquatic plant and animal life. Proper construction of impoundment dams and treatment of impoundment basins can prevent such occurrences.

Unless measures are taken by coal operators to seal and revegetate both coarse and fine waste upon abandonment of waste disposal areas, many unfavorable impacts can continue for decades. However, use of appropriate treatment methods on the part of coal operators, coupled with effective enforcement of waste disposal regulations promulgated by State and Federal Governments, can minimize such effects on the environment.

There can be beneficial uses of waste materials such as:

The waste rock removed during mining is in many areas utilized as landfill to provide level sites in deeply dissected terrains. This type of landfill is an effective method for disposal of mine waste when properly compacted, sealed, fertilized, reseeded, and revegetated.

Processing plant wastes when properly buried and revegetated at sites chosen according to sound geologic and hydrologic information, would have minimal environmental impacts in the thinly populated areas of the Rocky Mountain coal fields.

The return of mining and processing wastes to underground mine voids would lessen the potential for subsidence.

Synthetic Fuels from Coal

Through hydrogenation processes, it is possible to convert coal to various forms of liquids and gaseous forms as a substitute for natural oil and gas. Considerable research and development has been done and is in progress by the Federal Government and by private industry, and certain technologies have been demonstrated at commercial production scale which are not now economically competitive. Much of the work in progress is summarized in Department of the Interior's 1972 coal research report (USDI, Office of Coal Research, 1972).

The President, in his Clean Energy Message of June 4, 1971, and his subsequent budget requests, has given special attention to the acceleration of coal gasification. Similar acceleration of coal liquefaction technology development could result in economically feasible conversion processes that could provide an alternative source of oil, but even if these are done, in view of the critical domestic gas and oil supply situations that are developing the additional supplies so developed may not be available for electric-power generation.

The feasibility of using such processes as an alternative energy source depends upon the rate at which technological systems are developed, tested, and proven to be economically viable so that commercial scale plants could be built. It is possible that such could occur in time to produce substantial amounts of synthetic fuel by 1980-1985, but no meaningful forecast can be made at this time.

The environmental impacts of coal mining to provide the raw material for the production of synthetic fuels were discussed above. Environmental

considerations relating to the transportation and combustion of synthetic fuels are similar to those for natural oil and gas and are discussed in following sections. Because much of the Rocky Mountain coals are low in sulfur and are therefore in demand for power generation, it is doubtful that these coals will be used for the production of synthetic fuels before full development of the higher sulfur eastern coals. The deeply buried western coals may provide raw material for the synthetic production of oil and gas when in-situ conversion processes are developed. This is not expected to occur in the near future, and therefore this energy source is not really a viable alternative to geothermal steam production.

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Oil

Oil is used in electric power generation on the West Coast including the San Francisco and Los Angeles areas. It probably will continue to be used in increasing amounts if other power generating sources are not available. The West Coast currently is subject to a short domestic supply of oil, importing such oil as is needed above the amounts produced in the coastal areas. The principal geothermal power areas presently being developed or considered for development could supply increasing amounts of electricity to areas where oil is now used for power generation. Conversely, increased domestic production of oil or increased imports of oil could be used to supply increased power generating energy needs if geothermal resources are not to be developed.

The average heat in BTUs used to produce one kilowatt hour from fossil fueled thermal generating plants in California in 1970 was 9,604 BTU per kwh of electricity generated (Federal Power Commission, 1969, p. 2-120). These generating plants use oil or gas, somewhat interchangeably, although natural gas, a cleaner burning fuel, is more widely used in the Los Angeles area as an air-pollution control measure.

If oil were required to provide electric energy should geothermal energy not be available, the approximate following amounts of oil would be necessary to replace the geothermal electric energy predicted at intervals during the next 10 to 15 years.

Table 1.--Oil requirement needed in Western United States to replace electricity generated by geothermal means should geothermal power be restricted.[1/]

Year	Geothermal Power[2/]	Oil Replacement million bbls. per year
1972	192 megawatts from Geysers Field, Calif.	2.5
1980	1,000-2,000 megawatts from Geysers Field, Calif.	13-26
1985	7,000-20,000 megawatts from all western U.S. sources (assuming new technology can be developed to use hot water).	91-260

Much of the oil used in power generation on the West Coast is imported as a heating oil product because most West Coast refineries are designed to produce light oil products rather than heavy heating oil for power generation. If geothermal power were not developed, part of the increased power generation would probably be produced by oil-fired power stations, with increases in low-sulfur heating oil imports. Some other possibilities are described below in considering the impact of alternate oil sources.

1/ The average crude oil yields about 5.8 million BTUs per barrel (42 gallons) and the average low-sulfur fuel oil, a refined product, yields about 6 million BTUs per barrel. For this purpose, it is assumed that a low-sulfur crude oil yielding 5.8 million BTUs could be used in power generating facilities even though lighter fractions would probably be refined off and used for other purposes.

2/ Predicted geothermal power from National Petroleum Council, U. S. Energy Outlook, v. 2, 1971.

INCREASED DOMESTIC PRODUCTION--CONTERMINOUS STATES ONSHORE

It is generally accepted that some increases in domestic production would be necessary to substitute for the potential geothermal power development. This could be achieved through additional exploration and drilling onshore in the conterminous states. Such additional search for oil is not currently underway because the economic return is generally greater for investments offshore, in Alaska, or overseas.

The environmental impacts associated with substitution of the domestic production of oil for geothermal energy in power production involve exploration and production activities, the transportation of the crude oil, refining, and finally its consumption at the electric power plant. These impacts depend largely on local considerations, such as the site of an oil discovery, distance to refinery, means of transport, and siting of power stations. These matters are indeterminate with respect to individual developments at this time because we have no such substitute facilities. However, some general discussion of the impacts common to the domestic production of oil are outlined briefly hereafter.

Exploration and Production

Onshore exploration activities are similar to those of geothermal exploration, and environmental impacts are generally limited to temporary disturbance of terrain and denial of habitat to wildlife during exploration periods. Ordinarily geophysical exploration does not involve building new access roads or structures. Where preliminary geologic studies are favorable, a test well may be drilled. Depending upon the site this may

require construction of access roads sufficient to move very heavy equipment and grading of drill sites. In mountainous and wild areas such construction can have local adverse impact on the terrain, sediment transport, fish and wildlife habitats, and recreational and aesthetic values, whereas in level, developed country the impact of similar activities may be relatively insignificant.

Further development activity depends upon the success of test drilling; commonly one or two test wells, if unfavorable, may terminate a test program, and the terrain can be returned to the natural condition. If test drilling indicates a developable resource, major construction of roads, wells, collector pipelines, industrial and storage facilities, and waste disposal facilities generally follows. Impacts of such development can be wide-ranging including change in land use, denial of fish and wildlife habitat, air and water quality impairment, loss of recreational and aesthetic values and many lesser impacts. Most, if not all, adverse impacts, however, can be managed or ameliorated by proper land and resource management techniques, and conducting operations in a workman-like manner.

Transportation

Substantial oil production is normally served by a trunk pipeline to transport the crude oil to the refinery or to a shore terminal for transhipment by tanker to a refinery. Pipeline construction involves temporary disturbance of the terrain to the extent of the excavation of a trench, and the provision of crossing structures for streams, and location and construction of pumping stations. Once the pipeline is completed, it normally is a benign environmental consideration and terrain returns to

essentially its native condition. There are possible hazards of oil spills in case of line breakage, but normal pipeline maintenance and safety measures, etc. are designed to prevent large or long continued spillage.

Refining

Increased use of oil for electric-power generation as a substitute for geothermal power could require an increase in refining capacity to produce low-sulfur fuel oil. Such refineries tend to be located close to the heavily populated areas near tidewater and deep ocean harbors. Some air pollution, thermal pollution, and effluents of liquid wastes are normally associated with such refineries, but these are controlled to tolerable levels in most areas. Danger of explosions, fires, and oil spills exist in the refinery and associated oil storage areas. However, the incremental increase in refining capacity to produce low-sulfur fuel oil for power generation as an offset to geothermal energy probably would be managed mostly by expanding refinery capacity at existing plants without any significant increase in the adverse effects on the environment in the vicinity of the refineries. However, this is no reason for not developing geothermal resources since there still is forecast a large increase in electric power demand even in the West Region.

Oil-fired Thermal Power Generation Plants

The principal thermal electric power plants on the West Coast use natural gas by preference with interchangeable fuel oil when gas is in short supply. This region is also in the principal area of anticipated geothermal power development. The future use of low-sulfur fuel oil for power generation on the West Coast is projected to double by 1985, providing

a larger share of electric power. Oil-fired generating stations tend to be located near heavily populated areas so as to minimize transmission costs. They may have an adverse effect on air and water quality in such areas because of heavy population concentration. Also some of these plants could be unattractive in scenic areas. The oil-fired generating station produces more air pollutants than natural gas, but the air effluents generally could be held to tolerable levels except perhaps in the Los Angeles, California area. If oil were used to replace geothermal powered electricity, there would be an incremental increase in air pollution in the power plant areas.

Thermal pollution of lakes, streams, or ocean water from waste heat can be controlled; cooling ponds or towers are used if the heating of natural waters should adversely affect the water environment near the thermal power stations. Substantial amounts of water are consumed by the fuel-fired generating stations but where fresh water is in short supply, sea water can generally be substituted as a coolant.

INCREASED DOMESTIC PRODUCTION - ALASKA NORTH SLOPE OIL

Under the Trans-Alaska pipeline proposal, North Slope oil would be delivered to the West Coast. If the Trans-Alaska pipeline as proposed is not built, West Coast oil needs probably would be met by additional foreign imports. North Slope oil, however, could be considered as a substitute supply to geothermal energy in the West Coast areas.

The broad range of potential environmental impacts associated with development of production of 2 million barrels of oil per day from the Alaska North Slope oil resources are comprehensively covered in the

Department of the Interior's Environmental Impact Statement relative to the proposed Trans-Alaska Pipeline. (Interagency Task Force, 1972, Final Environmental Impact Statement Proposed Trans-Alaska Pipeline) Accordingly, no attempt will be made to include detailed coverage of the subject in this statement other than to highlight the nature of the types of potential environmental impact involved.

The proposed Trans-Alaska pipeline would pass through extensive areas of permafrost. Passage of hot oil through a conventional buried pipeline could thaw the permafrost, lead to unstable ground, and threaten the integrity of the pipeline. Accordingly, the pipeline has been designed so as to avoid significant thaw impacts. Much of the pipeline is in an area which has a history of seismic disturbances, and these can pose serious threats to pipeline integrity. Should the pipeline break, substantial quantities of oil could be released into the Arctic environment, which could enter streams, and spread over land areas thereby posing hazards to fish and wildlife. From the southern terminus of the pipeline, tankers would carry oil to the West Coast. Spills could occur from these tankers.

Alternative methods of transportation have been proposed. The most commonly mentioned is a pipeline through Canada; such a pipeline would avoid the tanker hazards, and would be less subject to breakage due to seismic disturbance; however, it would pass through more permafrost. Water transportation routes using icebreaking tankers or exotic transportation also have been proposed but such modes confront the dangers of spills due to collision with icebergs and difficulties in building environmentally safe, offshore terminals as well as the more usual hazards associated

with tanker operations. Oil spilled in the Arctic marine environment tends to be difficult to clean up due to the presence of ice and adverse climatic conditions.

INCREASED DOMESTIC PRODUCTION - CONTINENTAL SHELF LEASING AND PRODUCTION

This alternative would require increased exploration, development, and production of crude oil from offshore areas in the lower 48 states and Alaska. Current low domestic offshore drilling efforts, production at maximum efficient rates, and delays in scheduled leasing reduce or limit the attractiveness of oil as an alternative to geothermal energy. A significant increase in the production of crude oil supplies from offshore areas can come from development on existing leases and possible issuance of new leases and development of new reserves.

One hundred and seventy-one billion barrels of crude oil are estimated to be recoverable from the offshore areas of the United States under current technological and economic conditions--once they have been found. In terms of the ratio of production to estimated undiscovered resources, the offshore areas are more promising for economical development of additional reserves and production than are onshore provinces in the conterminous states.

Properly conducted petroleum exploratory and development operations should not have severe adverse impacts on the environment of the offshore areas. However, if oil spills occur, these could result in extensive short-term damage to beaches and wildlife and temporarily curtail other uses in the area of the spill. The long-term environmental effects of such a crude oil spill are not adequately known.

In the Outer Continental Shelf (OCS) areas of the U. S., there are 1,005 leases, comprising 4,261,661 acres. Six hundred of these leases, more than 2.5 million acres, have been proved productive. Nearly 80 percent of the leased OCS acreage is located offshore Louisiana, 14 percent is offshore Texas, and 6 percent is offshore California.

The proved oil reserves offshore California and Cook Inlet, Alaska are about 2 billion barrels. An additional prospective 4 billion barrels in identified but on partially explored accumulations in the OCS off California are currently undeveloped due to lease suspension.

Exploration and Production

The initial effort in offshore exploration involves geophysical exploration activity. Exploratory seismological surveys have little lasting impact; the principal effect is similar to the impact of surface use for commercial and sport boating on the marine environment. During development, disposal into the sea of trash, debris, bilge wastes, and spills of crank case oil and engine fuel could but should not occur from the variety of crew boats, service vessels, tugs, and drilling rigs which operate in the offshore area. However, existing regulating actions of the Coast Guard and the Geological Survey are designed to eliminate or minimize these occurrences. Inasmuch as exploratory drilling vessels or rigs occupy a single location for a limited period of time, the duration and the seriousness of any adverse environmental impact in the immediate vicinity of the drilling vessels or rigs depends on the magnitude of any pollution occurring there from such other characteristics as surface winds, tides, currents, bottom scouring, and water temperature, tend to concentrate, dilute through dissipation, or transport pollutants elsewhere. Most adverse environmental impacts can be avoided by the

enforcement of existing regulations and controls, and there are organized measures that will be taken if such spills do occur.

One of the major potentials for serious pollution of offshore waters by hydrocarbons is an uncontrolled flow of gas and/or oil from wells drilled from platforms or drilling vessels. This could be either a blowout during drilling operations or production mishaps from a failure of facilities. Normally, drilling muds and blowout prevention devices control the natural pressure in a well. Nevertheless, blowouts do occur in gas wells; oil blowouts are relatively rare, but they have occurred. Facilities can fail thus causing a release of hydrocarbons into the ocean, but with proper design, installation, and maintenance under existing OCS orders these can be minimized. The adverse impact depends largely upon the amount of oil that escapes to the marine environment and local characteristics noted above which control the distribution of the resulting pollution. With proper safeguards the adverse effects can be kept to manageable proportions.

Data compiled from the Pollution Incident Reporting System (PIRS) of the U. S. Coast Guard show that in 1970 there were 12 spills attributed to offshore oil wells. The total quantity of oil involved was estimated to be 111,900 bbl. When related to the 589,127,000 bbl of oil produced in off-shore areas, spills attributed to offshore production are extremely small (.0002 percent). There were 23 spills attributed to offshore pipelines with only one of significant size. Twenty-two spills were estimated to average 5 bbl. per spill. A total of 295 spills were attributed to barges. Average size of the spill was estimated at approximately 66 barrels per spill.

The construction of offshore drilling platforms can cause some temporary turbidity of the water which may damage aquatic life including shell fisheries located on the floor in the immediate vicinity of the facility; however, such turbidity would occur only during the setting of the platform structure.

There are over 14,000 wells in the offshore areas; of which 9,000 are in the Federally administered Outer Continental Shelf. The structures serve as drilling platforms, production and treating platforms, and crew living quarters. The geographic density of such units on Federal OCS areas vary considerably and generally most are three or more miles from shore. Platforms in some areas have desirable qualities which attract fish, and thus improve recreational values.

Transportation

Pipelines to transport oil and gas to shore terminals are buried to avoid disturbance by ship anchors as well as strong water currents. Approximately 98 percent of oil and natural gas produced offshore is transported to shore by pipeline. Although well blowouts attract the most attention, spillage of oil due to the rupture of pipelines also can result in serious pollution. It is estimated that during the last decade ruptured pipelines caused more pollution than drilling and production operations. During the past 10 years, over one-third of a million barrels of oil have been spilled into the sea off the U. S. through significant offshore accidents related to oil and gas operations. Some adverse impact similar to that during construction of drilling platforms described in the preceding section, must be expected during pipeline construction through disturbance of the bottom, but this is temporary.

Transportation of the crude oil to refineries and of refined products to the point of power plant use involves the same environmental impacts as described under onshore production.

When properly conducted and controlled, oil and gas operations in the offshore areas should impose minimal encroachment on the human habitat.

MODIFICATION OF PETROLEUM MARKET-DEMAND PRORATIONING SYSTEMS

This alternative considers the ability to obtain increased petroleum production from developed reserves that are being produced at rates less than maximum efficient rates. The alternative would require those states operating prorationing systems to revise their laws and regulations to permit such full production. This is not considered to be a viable alternative to projected geothermal energy as present indications are that proration restrictions soon, virtually, will cease to exist due to changing supply/demand impacts.

Production at maximum efficient rates at the current time might result in production increases in the range of 400,000 to 600,000 barrels a day over the short term and smaller increases over the long term without a significant environmental impact. Significant increases in exploration and discovery rates would be required before market-demand prorationing would be expected to have an impact on supplies in the 1976-1980 time frame. There is no indication of either at this time.

Elimination of state prorationing would result in some additional crude oil and natural gas being made available with little additional adverse impact on the environment. Minor increases in land and surface water pollution could result from factors such as increased pumping

requirements with resulting engine exhaust emissions, increased air contamination from burning dregs from heater treaters and waste in burning pits and possible increased flaring of noncommercial gases, and increases in small spills, ruptures or leaks that may occur in field lines or storage system.

Most excess capacity is in major fields where facilities either would or could be expanded to handle increased production. Production increases could be limited in the early phase by inability to process produced salt water and natural gas. Environmental and waste prevention requirements are such that production would be restricted in some areas where little spare capacity exists. Declincing spare productive capacity and increasing demand for crude will require production at maximum efficient recovery rates (MER) within the near future.

Inasmuch as prorationing is currently a state function which is likely to disappear in a few years, there is little incentive for the states to rescind their laws unilaterally. Negotiation with the states, repeal of the Connally Hot Oil Act, or attack on the prorationing system in the courts through antitrust suits could lead to litigation and considerable delay in implementing change.

Projections by the Office of Oil and Gas and the industry suggest that the increase in demand under current conditions will be such that prorationing will cease to function in fact by 1974 or 1975 even without any Government action. In that case, its elimination would not be an alternative for the period of interest as no further production acceleration could be expected.

It can be seen that this alternative is only meaningful for the short term, i.e. as a possible substitute for the present geothermal generating capacity of 192 Mw. As this is the equivalent of only 2.5 million barrels of oil per year, minor adjustments in production would suffice to account for this amount of oil. Thus, the option of modification of the prorationing system probably is not a viable alternative to geothermal power generation. This would be such a small increment in the total production in states where prorationing is in effect, that the incremental environmental impacts of increasing production would be negligible.

INCREASED OIL IMPORTS

Based upon a recent Department of the Interior analysis, estimated 1980 oil demand will most likely be 22 million barrels per day. The comparison of projected domestic production deficits relative to that projected demand under the various assumptions considered, ranges from 8 million barrels per day (41%) to as high as 16.2 million barrels per day (65% of demand). Such deficits must be provided for either by (i) reduction in demand, (ii) increased oil imports, or (iii) development of additional sources of domestic supply. Development of additional sources has been discussed previously and reduction in energy demand is discussed in a subsequent section. The alternative of increased oil imports could be accomplished in two ways: (1) increased imports under the Mandatory Oil Import Program, and (2) elimination of the Import Program controls, which would allow lower cost foreign imports to enter the United States to whatever extent market systems accommodate the use of such oil in lieu of domestic production.

A major issue relative to this consideration is the extent to which foreign import controls must be maintained to assure domestic production capabilities required to meet national security needs. The West Coast is under a quota system which allows overseas imports up to the amount required to meet area demands in excess of domestic production

and overland imports. In the absence of North Slope Oil, it is assumed that imports would continue to be allowed to come into the West Coast on this same basis. The question of increased imports therefore is primarily one of impact on other areas in the United States, rather than the West Coast.

In the event that geothermal power development is not implemented, imported oil could be a freely substitutable source. However, its use for electric power generation represents a relatively small part of the energy demand to be supplied by projected imports. It, thus, would have little bearing on decision making with regard to the oil-import program.

The environmental impacts of increased imports arise mainly from three sources: (1) increased ship traffic, (2) the transportation of the oil from offshore terminals to coastal refineries, and thence to power plants, and (3) consumption of the oil at the power plants.

At the present level of geothermal generating capacity of 192 Mw, an increase in the oil equivalent, 2.5 million barrels per year, would result in a negligible increase in tanker traffic. The U. S. Coast Guard, in a section prepared for the Trans-Alaska Pipeline Environmental Impact Statement, assumes an average tanker load of 800,000 barrels per vessel. Thus, only 3 tanker trips per year would be required for an imported oil substitution.

At the higher projected levels of geothermal capacity of 1,000-2,000 Mw and 7,000-20,000 Mw, roughly 15 to 30 and 100 to 300 tanker trips per year, respectively, would be required. Even these higher levels could be accommodated with existing facilities although the environmental impacts would be in rough proportion to the amount of oil handled.

The principal adverse environmental impact from tanker operations, which contribute to the pollution of the seas, stems from oil discharged intentionally during underway tank cleaning operations. The following discharge estimates were derived by extrapolation of U. S. Coast Guard estimates prepared for the Trans-Alaska Pipeline Statement.

Assuming transport of 250 million barrels per year (20,000 Mw equivalent) the expected rates of discharge would range from 185,000 barrels per year from uncontrolled operations to 16,600 barrels per year, assuming compliance with the standards proposed in the 1969 amendments to the International Convention for the Prevention of Pollution of the Sea by Oil, 1954.

The environmental impacts associated with land transport of imported oil to refineries and thence to power plants, and from consumption of the fuel are discussed elsewhere in this report.

The advantages of increasing oil imports as a substitute for geothermal power generation are principally that the adverse environmental impacts in the U. S. are restricted to those associated with transportation, refining, and power generation. In general these would be restricted geographically to harbors and load centers such as industrial cities where the small increase in impact would be relatively insignificant. Such impacts as impairment of aesthetic and recreation values, and denial of fish and wildlife habitat diminish in significance.

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Nuclear Energy

Additional nuclear power plants generating electricity could be substituted for geothermal electric generation. Three types of nuclear power plants theoretically are possible: burner (light-water or gas-cooled), breeder, and fusion. Only the first has reached commercial production. At the present time, neither breeder nor fusion reactors are practical alternatives and considerable research will be required to demonstrate their technical and economic feasibility. The only currently feasible nuclear alternative through the year 2000 would be to build additional nuclear power plants using burner reactors consuming naturally occurring isotopes of Uranium 235.

The use of nuclear power as a commercial energy source is expected to increase considerably in the next fifteen years. Installed U. S. capacity in 1970 was approximately 7000 Mw. This is projected to increase to 59,000-67,000 Mw by 1975; 105,000-150,000 Mw by 1980; and 300,000 Mw by 1985. The variance in these estimates is in part due to delays in the licensing of the construction and operation of currently planned or completed units because of concern over their environmental effects (from waste heat disposal, normal or accidental radioactive emissions, and the like).

Nearly all of the currently operating and planned nuclear plants utilize light water reactors. In these reactors, the heat energy created in nuclear fission is removed by the circulation of water through the fuel core to generate steam to turn turbine generators to produce electricity. In pressurized water reactors (comprising approximately two-thirds of existing or ordered capacity), the steam is generated indirectly utilizing a secondary cooling system. Four high-temperature, gas-cooled

reactors are also completed or on order in the U. S.. These utilize helium circulation through the fuel core to boil water creating steam to turn the turbine generators. On the basis of presently proven feasibility, a single nuclear power plant could substitute for geothermal generation at a level of 1000 to 2000 Mw capacity. For the higher estimated potential of 7000-20,000 Mw (National Petroleum Council 1972) some four to ten plants would be required.

The major environmental problems which could occur as a result of additional nuclear power development include the disposal of overburden, waste rock, and tailings from the mining of uranium ore, changes in land use, disposal of the waste heat generated by the thermally less efficient nuclear power plants, a very small risk of a disastrous accident, and insuring the safe transport and storage of highly radioactive waste materials.

Since specific impacts depend upon where the particular activities constituting the nuclear fuel cycle would be located, a description of specific impacts by location is not possible. Throughout this statement, the impacts described are considered to be a quantitative addition to similar impacts of existing or planned nuclear facilities.

Uranium Mining and Milling

The construction and operation of additional nuclear generating plants would require additional mining and milling of uranium ore to supply the fuel elements for these plants. An incremental operating capacity of 2000 Mw would require 1,070 tons of U_3O_8 for the first core fuels and 350 tons of U_3O_8 for annual reloads without plutonium recycling and 240 tons of U_3O_8 with plutonium recycling. At an average ore grade of 0.20 percent U_3O_8, a total ore output of 567,000 tons would be required to supply the uranium for the

first core fuels, and an annual output of 120,000 to 176,000 tons would be required for reloads. If the estimated 20,000 Mw geothermal capacity is realized, the fuel requirement would be proportionally higher. Since the average ore grade can be expected to decline during the life of the plants, the estimated annual ore tonnage for reloads would increase, particularly after 1990. As the estimated geothermal potential of 7000-20,000 Mw is small compared to projected nuclear development, whether or not the Federal geothermal program is implemented would have little effect on uranium production.

Uranium mining and milling in the United States is concentrated in New Mexico, Wyoming, the Colorado Plateau, and south Texas. As most of the known and potential reserves are concentrated in New Mexico, Wyoming, and the Colorado Plateau, the incremental mining and milling activity would be expected to occur there. In 1970, 53% of production came from underground mines, with the remainder coming from surface mines. This ratio of production between underground and open-pit mines is expected to be maintained over the next several decades.

The mining and milling of uranium ore creates certain environmental problems, particularly land use conflicts and biological hazards. Many of these can be prevented or minimized if known measures are utilized. If these measures are not taken, adverse environmental effects can be of significant proportions.

In underground mining, excessive exposure to radon daughter products is associated with a high incidence of lung cancer. The recommended annual exposure levels have been greatly reduced in the past decade. If these are maintained and enforced, the incidence of lung cancer among underground uranium miners is expected to be reduced to a level not significantly higher than that of the population as a whole.

Uranium mining is largely concentrated in relatively isolated areas distant from large population centers and urban areas. Nonetheless, it does have an adverse aesthetic impact in the areas in which it occurs, from the removal of the vegetative cover, the creation of overburden and waste rock, and the like. It also may require considerable acreage, reducing (depending upon location) the suitability of that area for other land uses such as grazing, wildlife, and some types of outdoor recreation. Open-pit mines especially require large acreages; expanded production from these mines would necessitate larger areas for placement of stripped overburden and other waste rock. This is a particularly acute problem for uranium as opposed to other types of open-pit mining, given the comparatively high amount of overburden removed for the quantity of uranium ore produced. For underground mining, the extraction of deeper ores will tend to require continually larger waste rock dump areas. Planning for sequential land uses, followed by the reclamation of mined land and the backfilling of mined-out stopes with waste rock, could, however, substantially reduce these land use problems.

Because of the low concentration of U_3O_8 in uranium ore, milling the ore produces a considerable amount of tailings. The uranium milling operation required for 2,000 Mw of capacity over a 25-year operating life is expected to generate around 4 to 5 million tons of tailings. These tailings contain radioactive daughters (such as radium). Left exposed on the surface, these tailings are subject to erosion and leaching, with the radioactive daughters entering surface and ground water systems. In areas down-stream from milling operations, concentrations of these elements substantially above recommended limits have been found in river

water, river sediments, flora, and fauna. The specific adverse effects of radioactivity on the overall health of biota are not fully known; current evidence does, however, indicate increasing concentrations upward in the food chain. Adequate methods do exist to prevent erosion and leaching and to retain harmful mill effluents at present levels of production. However, expanded production may require the design of improved systems to handle the growing volumes of waste if adverse effects noted above are to be avoided.

Because of their radioactivity, mill tailings pose long-term risks to human health if used as fill material. They are also a hostile environment for nearly all biota. Above-ground storage designed to minimize erosion, requires that the tailings be covered with gravel or dirt upon which a vegetative cover can be established. Above-ground storage does, however, require considerable land area, again displacing other potential uses. Subsequently, in the future an increasing amount of tailings may be utilized to backfill mined-out areas.

Power Plant Construction and Operation

Assuming present technical and economic constraints, the construction of additional nuclear capacity as an alternative to geothermal capacity of 2,000 Mw would require a single site. Under current siting criteria, this would be located at some distance from population centers and would require about 500acres of land from which most other human uses would be excluded. The higher estimated level of 7,000-20,000 Mw would require proportionally more land.

Since both nuclear plants and geothermal plants are generally located at considerable distances from population centers, land required for transmission rights-of-way would be comparable. Depending upon the capacity of the power line, an estimated ten to fifteen acres of land per mile of line would be required and this land would be excluded from development, although it would still be available for less intensive uses. These transmission lines would have an adverse aesthetic impact, disrupting some scenic vistas.

Construction of nuclear plant(s) would present some short-run environmental problems. Unless special measures are taken, erosion of excavated materials with subsequent siltation of streams can be expected.

Operation of a nuclear plant will generate considerable amounts of waste heat, however, these plants have a comparatively higher thermal efficiency (around 33% compared to 15 to 20% for geothermal steam generating plants). Given this difference in efficiency, geothermal plants, on average, consume considerably more cooling water and release more waste for a comparable generating capacity than do light water reactors. The effects of this waste heat will depend upon the cooling method used and the location of the plant.

The use of wet cooling towers, which are generally employed at geothermal plants, to remove the heat by evaporation into the atmosphere, would not pose problems of thermal pollution of water bodies. However, water vapor from the cooling operations can have substantial effects on local haze, fog, cloud, and ice formation. Chemicals released in the cooled water or evaporation plume could have adverse effects on downstream and downwind biota.

The use of cooling ponds would produce less evaporation than wet cooling towers, but haze, fog, cloud, and ice formation would still occur during periods of low temperatures. The ponds would require additional land acreage (an estimated 1,000-2,000 acres per 1,000 Mw unit). These ponds may have recreational uses, but they would also displace previous land uses.

Nuclear power plants, unlike geothermal plants, do not emit certain noxious condensible gases which generally accompany geothermal steam. Hence, they do not create the air pollution problems stemming from or requiring control measures for such emissions. However, nuclear plants do produce radioactive emissions whose release must be strictly limited if adverse affects to the health of humans and other biota are to be avoided.

In the normal operation of the incremental nuclear generating units, there would be very small amounts of radionuclides discharged in the cooling water and in gaseous plant effluents. But, assuming that present standards will be maintained and enforced (these limit the release of radioactivity to no more than would expose an individual at the plant boundary to 1% of the individual maximum allowed), the effects of the amounts released are likely to be negligible, as the average additional annual dose which the affected population would receive would be three to four orders of magnitude less than the average level of natural radiation exposure.

The operation of nuclear plants poses some risk of accidents. Nuclear plants are designed to minimize accidents or their adverse effects if one does occur, utilizing a "defense-in-depth" principle. This includes

designing and constructing plants in such a way that accidents are prevented, designing and constructing plants to contain the effects of accidents which may occur, and siting reactors away from areas of high population density. Plants are designed to withstand a design basis accident (DBA), defined as the worst malfunction considered to have a probability of occurrence high enough to warrant corrective action. For light water reactors, the worst DBA considered is usually a major rupture in the cooling system. The maximum radiation dose which could be received at the site boundary if such an accident occurred is estimated for some plants to approach the annual does obtained from natural radioactivity.

The ability of emergency core cooling to operate as planned if a loss-of-cooling accident did occur is disputed. Some responsible critics have suggested the need to consider more possibilities. With this uncertainty, the operation of many nuclear plants over an extended period of time can be considered to pose some risk of severe effects (ranging up to large numbers of injuries and deaths) with a very small but not definitely known, probability of occurrence.

Transportation

The nuclear fuel cycle from mining and milling through fuel preparation, power plant use and reprocessing, to the final storage of waste materials requires the transportation of radioactive materials by truck or rail at many stages. The transportation of spent fuel elements from reactors to reprocessing plants and of high-level wastes from reprocessing plants to storage sites poses a hazard of considerable magnitude. Existing transportation regulations and cask designs have been developed to insure that

even if accidents in transporting these materials do occur, no radioactivity will be released into the environment. For the transport of the spent fuels and high-level wastes associated with as much as a 20,000 Mw capacity, a small number of accidents could be expected to occur during a 25-year operating life. However, these are not expected to produce any major adverse effects other than those which could be expected from any other transportation accident.

Fuel Reprocessing and High-Level Waste Storage

Spent fuel assemblies from reactors are first partially cooled and then transported to fuel reprocessing plants where usable nuclear fuel materials are recovered from them. If 2,000 Mw of additional capacity were built, fuel reprocessing possibly could be accommodated at existing plants. The 7,000-20,000 Mw additional nuclear capacity that could substitute for geothermal development probably could be accommodated within projected plant development plans by the time such service would be required.

With present techniques, radioactive emissions during reprocessing are approximately 100 times greater than those occurring during normal power generation. For the period being considered, permissible release levels may be reduced. Even if they are not, the estimated dose to the affected population is still two orders of magnitude below natural levels. Hence, the impact of these emissions is not expected to be significant, even though the chronic effects of such low level radioactivity are not yet wholly known.

The high-level radioactive wastes remaining after reprocessing are first concentrated and stored in solution for five years, then evaporated to solids, sealed in containers, and put into long-term storage. The 2,000 Mw of

capacity would produce around 16,000 to 21,000 gallons of high-level waste per year, demanding a cumulative storage capacity of 80,000 to 100,000 gallons. This liquid waste, when evaporated, would yield around 160 to 220 cubic feet/year in solid waste materials for each year of operation.

Because of their high concentrations of radioactive nuclides with very slow rates of decay, these waste materials must be totally isolated from the biosphere for hundreds or thousands of years if serious adverse effects to all living organisms are to be avoided. Storage in salt beds is believed to pose fewer problems than any other method of storage. However, a wholly suitable site in salt beds for the permanent storage of solid waste materials has not yet been found.

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Oil Shale and Tar Sands

At the present time, there is no commercial production of oil from shale or tar sands in the United States. Much research has been done and is in progress, but no domestic process or technology has yet been developed and tested at a commercially and economically feasible production level. There is little question that large scale production is technically possible. The related economics, however, are highly uncertain until additional research, development and demonstrations have been completed to the point where there is sufficient information for economic evaluation of various alternatives, and even processes within each alternative, to the point where large capital commitments can be made with reasonable confidence. It is questionable if either of these sources could be considered as feasible alternatives for significant production by 1980, but there is high probability of substantial utilization of oil shale in the following decade. Acceleration of the development of either of these alternatives would probably require either intensive Federal research and development, or some form of Federal incentive or subsidy to stimulate private sector efforts.

It is doubtful that shale oil can be considered a viable alternative to geothermal power production under present economic constraints.

Development of oil shale solely as a substitute for geothermal power at the 192 Mw and 1,000 to 2,000 Mw levels would not be practical because that scale of oil shale development would be too small to be economically feasible. At the estimated level of 7,000 - 20,000 Mw of geothermal capacity the scale of substitute oil supply required would be of the order of the 1,000,000 barrel per day production projected by 1985 in the Department of Interior Proposed Prototype Leasing Program.

Consideration of tar sand development as an alternative to geothermal power is even more tenuous than oil shale development as there are no current known plans for major development in the United States that would represent a substitute energy supply for electric generation.

OIL SHALE DEVELOPMENT

Large areas of the United States are known to contain oil shale deposits but those in the States of Colorado, Utah and Wyoming are considered to have the greatest potential for commercial shale oil production. Some 73 percent of those oil shale lands, containing nearly 80 percent of the potential shale oil, are Federally owned. The highest grade deposits occur in an area of 17,000 square miles (11 million acres) and are capable of yielding an estimated 600 billion barrels of oil.

The President's Clean Energy Message of June 4, 1971, called for a program for orderly development of the Nation's oil shale

resources. The Department of Interior is currently considering the offering, in late 1972, of up to six prototype oil shale leases, 2 in each of the States cited. (U. S. Department of Interior, Program Statement for the Proposed Prototype Oil Shale Leasing Program, 1971).

Production of shale oil requires breaking up of the rock and heating or retorting it to produce a liquid petroleum product. Conventionally, the oil shale is mined, crushed and retorted in surface plants, however, shale oil has been produced experimentally by retorting of the rock in place, i.e., without mining it. This "in situ" technique is still essentially experimental.

The mining of oil shale presents no particularly difficult technological problems as it can be done by conventional underground or surface mining techniques. At least three surface retorting processes have been developed to the point of technological practicability, but none have been demonstrated and tested at a commercial scale. The major barrier to oil shale development then is the lack of any demonstration of mining and retorting at a scale sufficient to prove all the technology and to develop cost and other data necessary for determining economic feasibility.

The proposed prototype leasing program is intended to provide the opportunity for that demonstration and to provide the means whereby potential adverse environmental impacts can be detected and corrected before larger scale production is undertaken.

Because this program depends primarily on industry as to the timing of commercial production, it is not possible to determine if significant production from this source could be achieved by 1980.

It would be possible to accelerate the rate at which the necessary research, development and demonstration is accomplished by an accelerated direct Federal program or by some types of incentives or subsidies for the private sector effort. Under present policies, and if the proposed program is successful, substantial production could be achieved by 1985.

The following sections discuss the mining, processing and other activities, and the environmental impacts that would be associated with oil shale development in the States of Wyoming, Utah and Colorado. To the extent that oil from shale could substitute for geothermal power, the environmental impacts of geothermal development would be avoided.

From the National security standpoint, oil shale development would provide an additional major source of petroleum products within the continental United States.

Since much of the oil shale resource is on public lands, Federal regulations and controls could assure that adequate environmental protection measures are provided for in all development.

GENERAL

An oil shale industry even at the prototype level would involve very large investments, major industrial developments in currently rural areas, and resulting significant environmental impacts.

Any oil shale mining and processing system must provide for the handling and disposal of large quantities of material, the overburden, the mined rock and the spent shale or tailings. A significant factor is that spent shale (after retorting) occupies a larger volume than the original rock in place. Methods of handling these materials are discussed in the individual mining, processing and waste disposal sections.

The quantities of mined rock required for given levels of shale oil production and the volumes of spent shale residue are shown in the table on the following page.

Table - Volume of shale in place and after mining and retorting for various shale-oil production rates.

Shale oil production, Barrels per day	Shale mined, million ton per year	Volume of shale, billion cu. ft. per year 1/	
		In place	After mining and retorting
50,000	27	0.4	0.6 - 0.7
150,000	82	1.2	1.7 - 2.1
550,000	301	4.5	6.0 - 7.5
1,000,000	550	8.2	11.0 -13.7

1/ Dependent upon size of material discharged from retorting system.

UNDERGROUND MINING

Using the room-and-pillar method of underground mining, a maximum of 75% recovery of the shale would be possible. The remainder would be left as pillars to prevent surface subsidence. The ore would be raised to the surface and subsequently transported to the retort by truck or continuous conveyor belt.

Underground mining presents several advantages over open pit mining. First, only 2,000 acres of surface area over a 20 year period would be affected by an underground operation for a 50,000 barrels per day plant, as compared to 5,000 acres in an open pit development. Surface restoration needs would be minimal except around shaft openings and retort facilities. Wildlife and aesthetic values would be less disturbed under this type of operation.

While this type of mining, with most of its operations underground, requires less surface acres, the disposal of spent shale also must be considered. Two methods are available for waste shale disposal; (1) total surface disposal, or (2) a combination of surface disposal and return of the waste to the underground voids left by mining.

Total surface disposal would require the same amount of land as needed for open pit mining (56 to 80 acres per year). This acreage requirement could be significantly reduced by disposal of the waste material in the mine. As spent shale occupies a

greater volume than the original rock in place, only part of the waste could be returned to the mine (50 to 70%).

During the initial operation, while the underground mine is being developed, all waste would temporarily be stored above ground until sufficient mined-out space for disposal was available. For the 3-year period needed to reach full capacity, the required surface disposal area would approximate a total of 96 acres.

Spent shale disposed in underground mines could be subject to leaching if the mine workings were flooded while active or became saturated after mining operations ceased. Environmental controls such as sealing off aquifers with concrete have been adequate in similar type operations.

Since up to 70% of the waste could eventually be returned to the mine, potential dust problems from surface piles would be reduced. The shale crushing operation would require enclosed crushing and conveyor facilities, wherever possible, and protection of the piles of crushed shale from wind erosion before revegetation.

The disturbance of underground waters by mining operations, or water used to return spent shale underground for disposal, could have an adverse effect on subsurface water quality. Because hydrologic data of much of the region are incomplete, the extent of this impact cannot be predicted at this time. Specific information which has been developed through core drilling reduces the risk of leasing areas where unavoidable adverse impacts on aquifers are likely to occur. Close monitoring of the quality of underground

waters, and the prompt action required under the proposed program to change hazardous operations, would mitigate adverse effects.

SURFACE MINE DEVELOPMENT

This type of mining involves removal and disposal of the overburden to expose the oil shale for extraction. The quantity of overburden material significantly affects the economics and time-span involved in reaching production. Current surface mining techniques, using existing large-scale equipment, could be expected to permit mine development at relatively low unit costs, although costs for environmentally adequate waste disposal and land restoration may be expected to be greater than costs for underground operations.

Where surface mining is practical, it offers the advantages of greater recovery of the resource, more efficient operations and lower unit costs, less hazardous working environment than underground mining, avoidance of subsequent subsidence problems, and the opportunity to design the resulting land surface for improved productivity and land use.

Surface mining presents significant potential environmental problems. Land required for actual mining activity for a 50,000 barrels per day operation would directly involve from 200 to 250 acres per year, or 4,000 to 5,000 acres over a 20 year life of an operation. This amounts to 80,000 to 100,000 acres to achieve 1 million barrels per day over a 20 year span.

During early years of surface mine development, overburden

disposal would be off-site, probably in a temporary disposal area. After six or more years, it would be possible to begin disposing of overburden in the pit as a part of the overall reclamation process.

Such surface mine operation for a 50,000 bbl/day plant would require temporary off-site storage of up to 150 million cubic yards of overburden before pit return could begin. However, by properly selecting the disposal site and applying contouring techniques to control surface drainage, the area of land affected could be restricted to 400 acres and serious environmental impacts minimized.

The processed spent shale must initially be stored in an area away from the mine site. Return of the stored, processed spent shale to the pit could begin after pit development is completed (about 6 years). Some 100 acres of land surface would be required for temporary storage space.

During any open-pit mining operation, the topography will be altered and the environment changed. The actual area affected will be determined by the thicknesses of the overburden and oil shale, the mining plan, and the rate of development. Up to 5,000 acres could be involved, and this would be increased about one-third if waste material is not returned to the pit. In the long-term, open pits refilled with processed spent shale and overburden could be revegetated and the use of the site by wildlife and domestic grazing animals would return to a condition generally equal to and in some instances better than originally existed.

Waste disposal areas on flat land would create new "hills", which could be contoured and revegetated to prevent erosion and reduce aesthetic impacts. Canyon and gully disposal areas would

gradually be converted into flatter areas, and revegetated.

Restoration operations would include contouring to blend with surroundings; construction of conduits, retaining dikes and terraces to prevent erosion, control surface run-off, prevent downstream contamination, and provide paths for normal water flow; protection of any natural streams; and revegetation.

Revegetation would be an integral part of watershed protection measures. It has been experimentally demonstrated that vegetation can be grown on processed oil shale with adequate seeding, fertilization, and watering. A longer range vegetation goal would be the re-establishment of the natural plant community, or suitable replacement, to serve as wildlife food and cover. However, a significant amount of research experience indicates that re-establishment of the fuller range of native browse and cover species may be difficult.

PROCESSING

Oil shale processing on the surface would require the handling of large amounts of materials. The amount of oil shale needed to support shale oil production up to one million barrels per day, and the volume of both the shale in place and after mining and retorting, have been detailed in the table on page 61.

A number of retorting processes have been developed worldwide for the production of oil from oil shale. Three processes that have been tested using large experimental equipment appear at this time to offer reasonable possibilities of technical and economic success if scaled up to commercial design size. They are the Gas Combustion process developed by the Bureau of Mines, the TOSCO II process of the Oil Shale Corporation, and the Union Oil Company process. In each system, heat is applied to raise the temperature of crushed oil shale to about 900°F., where the solid organic material (kerogen) is converted to liquid. The equipment, method of heat application, and operating procedures differ markedly for each system.

A 50,000 barrel per day plant would be expected to occupy somewhat less than 100 acres for crushing, crushed shale storage, retorting, oil upgrading, oil storage, parking, office and shop facilities. The retorting plant itself would require five to ten acres of this total.

Off-site requirements for each plant would have an effect on the surrounding area to some degree. Access roads, power and gas transmission facilities, water lines, and oil pipelines would have

to be constructed. Because only one access road would be required for each site, relatively little land would be needed for road-building, although in some areas underpasses and suitable fencing might be required to reduce interference with wildlife migration patterns.

New power lines should be constructed in accordance with the environmental criteria outlined in recent Federal publications. Natural gas lines, if required, would be buried underground, using existing techniques for filling excavations, and reseeding of the right-of-way. Water supply lines would be buried, employing similar practices.

Oils from the retorting processes, with the possible exception of the TOSCO process, will require upgrading before the oil can be transported through pipelines to the final product refineries, which are expected to be located outside of the oil shale region. Modern refinery processes are suitable for subsequent upgrading. Each process also produces a retort gas that may be used within the plant as a fuel, or alternatively, to generate supplemental electrical power for nearby communities.

In the shale-oil upgrading process, the principal source of contaminated water would be from steam condensed in the gas-processing facilities, which would contain dissolved organic compounds. This water would be purified by conventional refinery treatment techniques and used in processed shale disposal or similar reclamation programs. The water used in the cooling tower also may contain high concentrations of dissolved salts.

Again, this would be conventionally treated and used in shale waste disposal.

The principal problems connected with an associated minerals extraction industry would be those concerned with solids handling in stockpiling the spent shale prior to dawsonite roasting and in disposal of the residue after alumina recovery.

No critical air pollution problems would be anticipated in connection with handling and utilizing the gases produced in oil shale retorting operations. Regardless of the retorting process, gases would be co-produced with the oil product. The mixture of oil and gas products would be conducted via a closed system from the pyrolysis section of the process operation to a separation and recovery section, in a state varying from true vapor to mist to liquid, depending upon the particular process and its operating conditions. Treatment to recover the maximum amount of oil possible also would remove water and particulate matter. The remaining product gases contain small amounts of sulfur, which may or may not be economically recoverable.

Any power plants associated with oil shale development would produce stack gases which could be sources of air pollution. Such contamination would be avoided by using the adequate emission control techniques for removal of particulate matter and by the control of sulfur and nitrogen oxides emissions through the use of low sulfur fuels, combustion temperatures control, and scrubbing.

IN SITU DEVELOPMENT

An in situ system involves the recovery of oil from the

oil shale by heating it underground in its natural place. This technique is called in-situ retorting and has not been successfully developed or demonstrated on a large scale, although considerable laboratory and field research has been carried out by government and industry.

Presently proposed heat sources for in-situ recovery include underground combustion, hot natural gas, hot carbon dioxide, superheated steam, hot solvents, and combinations of two or more of these. It is anticipated that conduits for introducing air or heat underground would be provided by wells, mine shafts and tunnels, fractures created by a variety of techniques, or by a combination of these.

Surface operations for in-situ recovery would be relatively less extensive with the absence of problems associated with mining and spent shale disposal. Disturbance of the original land surface and vegetation would be minor. Earth moving would be limited mostly to grading for well locations, plant site, and field roads. It is anticipated that less than ten percent of the land surface over an in-situ recovery project would be affected at any one time.

The contamination of underground water could pose a problem All presently contemplated techniques for such in-situ operations involve establishing permeability by fracturing, which could change the existing hydrology, thus introducing problems. For this reason, only limited in-situ operations would be permitted initially, and these would be closely monitored to prevent environmental degradation. Prior to authorization of commercial in-situ processing,

adequate control methods would have to be proven.

WASTE DISPOSAL

The residue or spent shale resulting from surface retorting is in the form of solid particles ranging from three inches in diameter to a fine powder, depending on the retorting method used. It will normally be dry, but it may be wet if it is processed to recover saline minerals. Extraction of saline minerals would minimize the possibility of leaching of them into groundwater supplies. Methods of disposal will therefore depend on the physical characteristics of the material, its water content, and the location of the disposal area, whether surface or subsurface. If it is to be returned to the mine, this will affect the mine development plans.

In an area broken by deep gullies or arroyos, the waste could be used to fill in these depressions and generally change the landscape. Great care would be required to prevent surface water from eroding the waste material into main streams and rivers. If a room and pillar mining system is used, much of the waste could be returned to the mine and thereby prevent subsidence.

Improper handling of overburden or spent shale in surface disposal operations could create windblown dust or permit sediments to be carried from the waste piles by surface waters. The extent of this problem would depend largely on the nature of the material being handled and how it is treated before or during the disposal process. At present, either wetting spent shale piles, followed by compaction and revegetation, or perhaps disposal as a slurry,

followed by dewatering, would appear to be one of the most feasible methods of controlling dust and sedimentation.

The rate of waste buildup on a typical 22 acre disposal site from a 50,000 barrel per day plant (approximately 250 feet per year) would far exceed the buildup of soil mositure from the low annual precipitation of one to two feet. Because of this, the water from precipitation would not saturate the waste material during the emplacement process. To prevent future ground water contamination, however, it may be necessary initially to construct a permanent impermeable floor where the waste material is to be deposited. This barrier would prevent the leach waters from entering underground water systems and would direct percolating waters toward the impoundment dams where they could be controlled for treatment, evaporation, or use. However, mineral leaching by water percolating through the waste piles is not anticipated to be a significant problem since compacted and moistened retorted shale has been shown in experimental tests to be of low water permeability. Natural cementation also takesplace over relatively short time periods, particularly when the spent shale has been moistened and compacted, tending to minimize surface leaching and erosion.

Design concepts for controlling sediment problems may include canals and culverts to carry runoff water around and/or under the disposal site. Protection against flash floods common to the area could be provided by upstream dams and canals to divert

the storm runoff from the waste pile; retaining dikes and terraces could reduce the sediment yield to the streams to an amount less than the same areas contribute under natural conditions.

Shale oil would be moved to refinery centers via connecting pipelines from the sites to existing transcontinental pipelines. These ten to twelve inch connecting lines could be constructed in some cases using existing rights-of-way to ensure minimum surface disturbance, with appropriate revegetation and positive maintenance to prevent leakage. The pipelines would avoid major earthquake regions; maintenance would be reduced because of lesser opportunity for breaks caused by natural disasters.

The extent of impacts from oil losses, if they were to occur, upon habitat and associated wildlife and fish populations would depend upon numerous factors, including: volume of oil lost, leak location, and weather conditions; the quantity and quality of wildlife and fish habitat affected; timing with respect to organism life history stages; and effectiveness of contingency plans. Most significant impacts would be on aquatic organisms and water-related birds and mammals. Such impacts would be minimized by building oil handling facilities and routing pipelines to avoid the more vulnerable habitats.

Construction of the pipelines together with the accompanying service roads would cause disruption of the vegetative patterns in a semi-arid region, but revegetation of the construction zone and maintenance of the service roads should minimize any adverse effects of this construction. Construction of service roads would

provide public and hunter access to a presently little-used areas and will place pressure on wildlife.

OTHER IMPACTS

Water Use and Quality

One of the greatest possible impacts would be in the requirement for water for the retort plants and the disposal of waste water. Approximately 290,000 acre feet annually would be required for 2 million barrel per day of shale oil production.

In addition, as much as ten gallons of water per ton of shale could be produced in the surface retorts. This water could contain dissolved saline and organic compounds. It could be used to moisten the waste shale to prevent dust problems. However, it would require treatment prior to other uses to remove hydrocarbons and malodorous compounds, and perhaps dissolved minerals.

Large quantities of natural ground water occur in leached zones of the deep oil-shale areas, but the location, composition and movement of such waters have yet to be defined in many areas. These aquifers may contribute substantially to the overall water supply available to satisfy requirements for oil shale development.

Use of ground water in oil shale development could decrease the natural discharge of springs and seeps. This could result in adverse effects on associated vegetation, and any fish or wildlife dependent on that water supply. Careful lease site selections to avoid natural water features which provide aquatic-habitat and development of alternate water sources for wildlife would prevent or mitigate such effects.

Degradation of water quality could occur from discharge of product or waste waters, siltation of streams, or leaching of saline minerals from

spent shale. It could be avoided in most cases by proper design and equipment with adequate supervision and monitoring of operations. Leaching of spent shale would not be expected to be a problem because properly emplaced waste sites will harden through natural cementation.

In addition to these waters, there would possibly be a water slurry produced by a wet scrubbing process used to remove fine dust in gas streams. The slurry from the wet scrubbing could be used to wet spent shale.

Water would also be used in the cooling phase of the process, but the amount needed could be kept to a minimum by employing air cooling. Any "sour" water streams produced by accidental contact with oil in final water condensers would be treated by conventional oil refinery methods.

The nature of the foreseeable problems associated with water quality would depend largely upon the mineral characteristics of the processed shale and the method of disposal. The foreseeable problems, which have been outlined, are believed controllable with present technology.

Air Quality

The principal sources of potential air pollution in an oil shale development would be solid particulates resulting from mining and spent shale disposal operations, dust produced during crushing and retorting operations, process stack gases from retorting, refinery by-product gases from shale oil upgrading, and any gases from electric generating plants or similar processes.

Potential dusting from surface waste disposal piles, mentioned previously, would be prevented by moistening the material and using disposal and revegetation techniques already under development in field tests. If residue shale were transported in dry form, covered conveyors may be required.

Wildlife Impacts

Certain areas of the oil shale region provide a habitat with an attractive combination of vegetative, climatic, physiographic, and cultural conditions for nearly 300 species of wildlife. Fishery habitat is limited and inhabited principally by non-game fish populations.

Probable and potential impacts on wildlife and fish are of two general types; localized impacts at and in the vicinity of the actual oil shale operations and impacts resulting from ancillary urbanization and human pressures.

Construction and operation would have varying degrees of direct and indirect impacts upon fish and wildlife and their habitat in the immediate vicinity of mining plants and along their

appurtenant roads, surface facilities, and pipelines. The impacts would include such things as alteration of wildlife behavior and activity patterns; removal and reduction of food and cover through removal of overburden and surface vegetation for mining, roads, plants, etc.; and wildlife disturbance from noise of mining and industrial operations.

Aquatic habitat is very small in the oil shale areas. However, were an oil shale operation established within the vicinity of such habitat, changes in the quality of local surface or ground water were to occur, there could be impacts on fish populations. Additionally, if use of ground water for development and operation caused a lowering of natural ground water discharges, such as springs and seeps, potential adverse impacts on associated ecological features would result. Supplemental habitat water development programs such as wells and reservoirs might be required.

Certain species, such as mountain lion, bear, elk, and mule deer are by nature incapable of adjusting to the aggregate of human activities in a developing area (i.e., urban expansion, waste disposal, additional recreation use, etc.). Although populations of these species in the oil shale areas would be expected to decline over time, as a result of oil shale production and population pressures, they should not decrease to the extent that any species would become rare, endangered or extinct. Added hunting and angling pressures indirectly resulting from improved access and increased local population could reduce hunting and angling quality for some species and in local situations where there is reduced

animal population and/or increased hunting pressure.

Land Use and Social Impacts

The oil shale lands in Colorado, Utah, and Wyoming are located in a sparsely settled, semi-arid to arid region of moderately high elevation. The oil shale areas are now used primarily for livestock grazing, agriculture, or recreation, therefore, some changes in use patterns would result with development.

Development of public oil-shale lands would have little direct impact on agricultural activities, since most agricultural lands are privately owned. However, some impact could occur if oil shale activities jeopardized water resources traditionally used for irrigation purposes.

The magnitude of the impact oil shale operations could have on the region's aesthetic, cultural and recreational qualities would depend on the location of the site, its size, and the system of extraction and processing as well as the operating practices followed. The oil shale area is generally remote, although little of it can be considered true wilderness. Present access, ranching, mineral extraction activities, and recreational use (principally hunting) would seem to preclude that terminology. "Semi-Wilderness" may be an appropriate term.

Some stretches of the Green River may qualify as either a wild or scenic river under terms of the Wild and Scenic Rivers Act of 1968. A section of the Green River in Utah is a designated Historic Site.

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TAR SANDS

Tar sands and bituminous sands are terms used to describe hydrocarbon-bearing deposits distinguished from more conventional oil and gas reservoirs by the high viscosity of the hydrocarbon, which is not recoverable in its natural state through a well by ordinary oil production methods. Reservoir energy is typically non-existent or minimal, so that for production to be initiated and sustained, some form of energy (heat, fluid pressure, mechanical work by mining machinery, etc.) must be applied.

Many such deposits are known, but only a few are likely to become of major commercial interest to North America, and to the United States in particular, in the next 15 to 30 years. Chief among these few are the Athabasca deposit in northern Alberta, Canada, and the Orinoco deposits in eastern Venezuela (National Petroleum Council, 1971). The National Petroleum Council's (NPC) Study on the U. S. Energy Outlook (1971) for the period 1971-1985 considered only deposits with tar sand resources of 0.5 billion barrels or more to be worth evaluating as potential sources likely to affect the United States energy supply. Only five such deposits were identified in the United States. These five deposits, all in the State of Utah, are estimated to contain a total of about 17.7 - 27.6 billion barrels of tar sand resources in place, based on outcrop data and relatively few drill-hole observations. Therefore, the NPC study concluded that

domestic tar sand resources are unlikely to have an important role in the United States energy supply through 1985.

The following factors will probably deter early development of the Utah deposits (NPC study 1971; Ritzma 1969, 1970):

The Tar Sand Triangle and Circle Cliffs deposits are largely on Federal lands. Leasing of Federal lands for asphaltic minerals or tar sands is not permitted under existing law.

Proposals for national parks, national monuments, desert wilderness areas, and recreation areas cover most of the Circle Cliffs and Tar Sand Triangle deposits and could result in surface used incompatible with mineral resource development.

Lack of suitable water supply may constitute a serious handicap to exploitation of the Utah deposits.

Most Utah deposits are not susceptible to mining, but more likely will be developed by in situ methods, the technology for which has yet to be perfected.

While resource estimates have been made for the Utah deposits, no estimates are available as to the potential reserves recoverable. The recovery by in situ methods, is estimated to be only in the order of 35-50% of the resource in place.

The initial development of tar sand production technology has been in the Athabasca region of Canada, since it is there that the largest and most accessible tar sand deposits occur. The

National Petroleum Council (1971) estimates that 174 billion barrels may be economically recoverable; the Alberta Oil and Gas Conservation's Board's estimates are even higher. Others have estimated that as few as 85 billion barrels are currently minable (Schurr and Homan 1970). No United States deposits are as rich as those of Athabasca.

The difficulty of the tar sand extraction process has caused synthetic crude from tar sands to be more expensive than crude from conventional sources. Recently, however, Great Canadian Oil Sands, Limited, in Alberta, Canada, has enjoyed sufficient success to suggest that tar sands could become competitive and Syncrude Canada, Limited, has applied for expansion of capacity (Syncrude, 1971a).

Although a decision by the Canadian Government to accelerate the exploitation of tar sand potential might significantly increase Canada's crude oil production and exporting potential by 1985, it is unlikely that the United States production under existing economic conditions will begin and contribute significantly to domestic supply by 1985. (Canadian production is currently limited by licensing requirements in addition to the technical factors.)

The NPC study (1971), based on experience in tar sand mining in Canada, reached the following conclusions with respect to production by strip-mining methods; "The mining-extraction route

is most applicable to the shallow deposits (up to 100 or 150 feet of overburden). Because the bitumen content of average sand is normally less than about 12 percent by weight, an immense tonnage of sand and overburden must be moved, using strip mining methods, to support an economically large synthetic crude output. The ratio is about 2.4 tons of sand and 1.0 ton of overburden, more or less, per barrel of synthetic crude. An overall average utilization of total tar sands in a mining leasehold may be on the order of 75 percent."

Strip mining offers the highest recovery rates and most economic return per unit area subjected to exploitation but causes maximum disturbance of surface area subjected to exploitation. Few large United States deposits will be susceptible to strip mining methods because of the depth of overburden. Materials filed by Syncrude of Canada in support of their application in Canada (Syncrude, 1971b) for amendment of their license to produce additional oil from tar sands provides some indication of the nature of operations and their impact on the environment. The impacts would also be somewhat analogous to those of producing oil from oil shale (USDI, 1971).

Overburden would have to be removed and stored temporarily until excavation had advanced far enough to permit its replacement in the mining pit. (Syncrude anticipates only thirty-three feet of overburden and low-bitumen reject sands--less than for many possible oil shale operations--so that the extent of overburden

problem would be limited.) Production of 125,000 barrels per day for thirteen years would be from an area of 5.5 square miles. Surface facilities for extraction of the bitumen would require about 200 acres of land.

Plans for using underground mining methods and techniques for the development of tar sand resources as an energy source are unknown at this time. In situ methods will more likely be used for recovery from deposits at depths not susceptible to strip mining, inasmuch as many tar sands are not well cemented and would tend to slump or cave if underground mining methods were used.

At present there is no commercial-scale technology available for in situ recovery of tar sand resources, although this method is being tested in a pilot plant stage. The method holds greatest promise for recovery of United States deposits.

The NPC's 1971 study reached the following conclusions with respect to in situ methods;

"The two methods most thoroughly researched and tested in the field involve (1) injecting steam plus an emulsifying agent (e.g., caustic soda as used in a Shell Oil Co. trial) into the deposit and (2) using thermal-recovery or 'fire-flooding' techniques as experimented with by Amoco (Canada) and others. For either method to succeed, communication must be established down-hole in the formation between the injection wells and the production wells. Field tests have determined that this can be achieved. Overall recovery of in-place bitumen via either in situ technique is estimated to be on the order of 35 to 50 percent, distinctly lower than the corresponding value for mining extraction."

In situ processing would result in minimum surface disturbance. Well locations would utilize only a small percentage of the surface. There would be no sand tailings and resultant disposal problem. However, recovery rates are lower than that achieved by strip mining and therefore greater areas would have to be subjected to development in order to achieve the same volume of production and much of the resource potential would be lost.

Many of the various potential environmental impacts associated with the mining of oil shale as outlined in the preceeding section would be similarly applicable to tar sand mining.

The NPC study of 1971 gives the following analysis of processing of the bitumen from tar sands, based on current operations by Great Canadian Oil Sands, Ltd. (GCOS) and plans by Syncrude Canada, Ltd. for upgrading the Athabasca tar sand deposits to a synthetic crude suitable for pipeline distribution.

"Upgrading of bitumen to synthetic crude suitable for shipment to refining-marketing centers for manufacture into finished products involves hydrogen-enrichment of the bitumen by some means. Also, for a fuel-balanced operation, necessary in the remote locale of major tar sands deposits, sufficient bitumen or components thereof must be set aside as fuel for the operation, and for production of hydrogen. These requirements result in a synthetic crude product/bitumen volume ratio of from about 0.78 (GCOS, via coking and hydrogenation of coker distillates) to 0.87 (Syncrude, via hydrovisbreaking plus hydrogenation of visbreaker distillates). Presumably in situ bitumen would be upgraded in about the same ratio to make a similar synthetic

crude."

Commercial-scale processing methods for substantial reserves of tar sands in Canada have now been developed. These methods may be directly applicable to processing of United States deposits, if and when they are developed, without extensive pilot-plant operation. The coke from the up-grading process is recycled as a fuel for the refining operation and not left as a waste product.

Particulate matter and gases containing sulfur dioxide would be released to the atmosphere during tar sand processing, but such release could be mitigated by control devices using existing technology.

Pre-refining by hydrogen-enrichment of tar sands in Canada has resulted in a superior feedstock for pipeline shipment to refining.

Both the Canadian and the United States deposits in Utah may take advantage of nearby existing pipeline facilities.

According to Cameron (1969) "Present production from the GCOS plant is moving primarily to the Great Lakes area, some into the United States. The oil will have traveled 1,925 pipeline miles to its destination in Sarnia, Ontario."

Waste associated with tar sand extraction would include sand tailings, overburden, coke, sludge, sulfur dioxide emissions, nitrogen and metals.

Coke obtained from processing is utilized as a fuel for the refining operation. Sulfur could also be recovered as a by-product. Initial plans by GCOS were to recover 45,000 barrels

of synthetic crude, 3,000 tons of coke, and 300 tons of sulfur a day. According to the 1971 NPC study, "In the process of hydrogen-enrichment, the sulfur and nitrogen contents are reduced to tolerable levels via hydrogenation and the metals exit with the carbon residue.***"

If in situ technology is perfected, the waste disposal problems associated with strip mining will be eliminated.

As stated previously, under "Production", on a unit basis, there are about 3.4 tons of waste material (2.4 tons of sand and 1.0 ton of overburden) more or less per barrel of synthetic crude produced using strip mining methods in the Athabasca area currently under development.

The tailings (sand from which most of the bitumen has been removed) are, in the Syncrude operation, initially deposited in a diked area (retention pond, 9.32 square miles) to prevent contamination of water supplies by runoff. Subsequent tailings would be returned to the mined area. The extraction process uses water and produces an oily sludge as a byproduct. The Syncrude process places the sludge in the man-made tailings pond; failure to make suitable provision for disposal of sludge and tailings could lead to contamination of water supplies.

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Gas

At the three projected levels of geothermal development considered herein, gas alternatives would be as follows:

Geothermal Capacity, Mw	Gas Equivalent (Trillion BTU Per Year)
192	5
1,000 - 2,000	27 - 54
7,000 - 20,000	190 - 540

Currently gas is the major fuel used for generating electricity in California, where it accounts for three-fourths of the steam electric generation. Major electric plants use natural gas on an "as available" basis shifting quickly to fuel oil during periods of peak gas demand. However, in view of the expected high future demand for gas for other uses, it is not expected that fossil-fuel additions to steam generating capacity on the West Coast will use scarce gas supplies, but will rely instead on low-sulfur content fuel oil. The projected annual gas demand for electricity in PAD District V[1/] has been estimated to be 1,050 trillion BTU (TBTU) for 1975, 1,147 for 1980 and 1,315 for 1985 (National Petroleum Council, 1971). However, during the same periods of time the shortfall in demand over supply has been estimated to be 980 TBTU in 1975, 1,510 TBTU in 1980 and 2,240 TBTU in 1985. With an estimated constant supply of some 54 TBTU geothermal resource potential during these same periods, it would appear that gas is not a feasible alternative in that there will not be enough gas to supply the demand let alone serve as an alternative for geothermal resource

1/ PAD District V embraces California, Oregon, Washington, Nevada, Arigona, Alaska, and Hawaii.

could serve to supplement the shortfall in gas particularly in the category where gas is used for producing electricity.

The relatively low price of natural gas has not only stimulated the rapid use and decline of natural gas supplies, but along with inflated costs, it has diminished incentives to search for and develop new natural gas deposits. Total proved reserves of natural gas as of the end of 1970 were 291 trillion cubic feet. Estimates of reserve additions between 1971 and 1985 in the conterminous states would total 141 trillion cubic feet. The significance of the ratio of proved reserves to annual domestic production (RIP) is important. After World War II the RIP rate exceeded 30 to 1; by 1964 it had declined to 18 to 1; and in 1970 to 14 to 1. It is not clear as to what the minimum tolerable RIP ratio should be, but based on industry experience a RIP of 10 appears to be the minimum that could be tolerated without significant and recurrent curtailment in service.

Ways to increase gas reserves are:

1. Increase price of natural gas
2. Nuclear stimulation of known reservoirs
3. Increase Foreign Imports
    a. pipeline gas
    b. liquified natural gas

The Federal Power Commission is already moving in the direction of increasing the price of gas. Such an increase would be expected to increase natural gas explorations and hopefully to lead to improved discovery rates. Since natural gas is by far the least polluting of the fossil fuels, additional use would benefit the environment.

Nuclear stimulation of known gas reservoirs has many built-in adverse environmental hazards and although it may unlock new resources, much research and development effort will be required. It would not be expected to provide important additions to reserves over the short term.

Increasing imports of foreign natural gas or liquified natural gas poses problems of foreign control of our fuel supplies. It necessitates increased transportation and storage facilities and increases our balance of payment problems. Imported liquified gas is a less economically viable alternative to geothermal electric generation because of its high cost in relation to other imported fuels.

Essentially then it appears that natural gas is not a viable alternative to geothermal power generation under present economic constraints.

In the event that gas could substitute for geothermal power, the environmental impacts would be somewhat similar. Both sources require drilling to tap energy reservoirs, construction of pipelines, electric powerplants, and transmission lines. Both have minimal air quality impact, and water quality impacts are controllable with currently available technology. A major difference is that geothermal powerplants must be located close to the heat source, while gas can be transported great distances in pipelines. Normally, gas-fired electric generating stations are sited close to load centers to minimize electrical system distribution losses, while geothermal power must be transmitted over power lines to the point of energy use.

The impacts of natural gas production, pipelines, powerplants and transmissionlines depend largely on the local impacted environment; hence the local impacts of natural gas as a possible substitute for geothermal power cannot be evaluated at this time.

Hydroelectric Power

The potential of hydroelectric capacity is limited. Of the 100,000 Mw capacity estimated as potentially developable in the conterminous states approximately only 30,000 Mw is likely to be developed by 1990 under existing programs. The potential sites would most likely be developed to provide area load peaking capacity requirements in conjunction with fossil-fuel or nuclear base-load plants.

The generating potential of any hydroelectric site is a function of both stream discharge and the height of fall. The better hydroelectric sites are concentrated in areas with heavy precipitation and large topographic relief. The following table shows the extent of U. S. potential and developed water-power capacity:*

Geographic Region	Potential Power (10^3 Mw)**	Percent Of Total	Developed Capacity (10^3 Mw)	Percent Developed
New England	4.8	2.7	1.5	31.3
Middle Atlantic	8.7	4.8	4.2	48.3
East North Central	2.5	1.4	0.9	36.0
West North Central	7.1	3.9	2.7	38.0
South Atlantic	14.8	8.2	5.3	35.8
East South Central	9.0	5.0	5.2	57.8
West South Central	5.2	2.9	1.9	36.5
Mountain	32.9	18.3	6.2	18.8
Pacific	62.2	34.6	23.9	38.4
Alaska	32.6	18.1	0.1	0.3
Hawaii	0.1	0.1	---	---
Total	179.9	100.0	51.9	28.8

* Statistics as of January 1971 obtained informally from FPC

** Mw = Megawatts

Of the potential hydroelectric capacity of 179,900 Mw in the U.S., 28.8 percent or 51,900 Mw has been developed leaving approximately

130,000 Mw developable. Of this 130,000 Mw of capacity some 32,600 Mw is located in Alaska. Sparsity of population and remoteness from population centers make the economic feasibility of large hydroelectric projects in Alaska subject to considerable doubt. Of the approximately 100,000 Mw of capacity yet to be developed in the conterminous states 65,000 Mw are concentrated in the Mountain and Pacific Regions. About 35,000 Mw of capacity potential could be developed in the remainder of the United States.

The Federal Power Commission projects electric generating capacity in the U. S. as follows:

Year	Total Generating Capacity (Mw)	Total Hydro Capacity (Mw)	Hydro as Percent of Total
1970	340,058	51,641	15.2
1980	665,000	68,000	10.2
1990	1,260,000	82,000	6.5

Thus, by 1990 development of approximately half of the Nation's total hydropower potential will comprise only 6.5 percent of total electric generating capacity.

The 38,000 Mw hydroelectric capacity estimated as being developable in the Pacific States is of the magnitude that could be considered as a short-term substitute for geothermal power. At the 192 Mw level, a single medium-sized power project could substitute for geothermal; at the 1,000-2,000 Mw level a project of the scale of Grand Coulee Dam on the Columbia River (2,276 Mw) would be required; and at the 7,000-20,000 Mw level several large projects would be required as a substitute. Since those hydroelectric power projects which are economically feasible will be built to meet increasing power needs of the West Region, such

development does not appear to represent a viable long-term alternative to geothermal resource development.

It should be noted that few dams are built solely for hydroelectric power generation. Irrigation, navigation, municipal, and industrial uses, as well as flood control are important, and frequently are the dominant objectives for the project.

Numerous environmental impact statements filed by the Bureau of Reclamation of the Department of the Interior and by the Corps of Engineers describe environmental impacts of specific hydroelectric projects.

Hydroelectric power produces no air pollution, radioactivity, or waste heat, and causes minimal water quality deterioration (with the exception of nitrogen supersaturation and the loss of oxygen content in storage reservoirs. Impacts on land and water resources tend to be limited to the vicinity of the power generation site. Dams valuable for hydroelectric purposes may be otherwise useful for such needs as irrigation and flood control. Lakes behind dams created for hydroelectric purposes provide recreational opportunities such as swimming, fishing, and boating.

Construction of a hydroelectric dam represents an irretrievable commitment of the land resources beneath the dam and lake (agriculture, minerals, wildlife habitat, free-flowing river recreation, etc.). Alteration of river flows may lead to silting behind the dam, thus progressively reducing reservoir capacity and its effective use, and finally, after many years, filling of the lake. Alteration of downstream flows from powerplant discharges can cause scouring of river banks and bottoms.

Fish and wildlife habitat may be adversely altered. The reproductive habits of anadromous fish may be severely altered by dam construction, unless elaborate provision is made for fish ladders or other means to provide safe fish passage.

Other Energy Sources

There are other potential energy sources which need to be recognized as possible energy alternatives to geothermal power development. At present, these alternatives are not considered viable due to a lack of proven technology for production scale application, costs, timing of development, location relative to energy demand, environmental impacts, etc. These include improved fuel use efficiency, tidal power, solar energy, biological conversion of wastes to oil, and the use of liquid hydrogen as a motor fuel.

Potential environmental impacts of exotic alternatives are difficult to assess, particularly where there is a great amount of research and development that must be done before operational scale systems can be developed, tested, evaluated and readied for production application. It is not believed that any significant energy production can be obtained from these systems. Essentially, these are all in the research and development stage, and, while some discussion of potential environmental impacts is included, it is not possible to develop a full discussion due to the lack of necessary data. The following sections briefly describe the current and short-range status of each of these potential alternatives.

MAGNETOHYDRODYNAMICS

Magnetohydrodynamics (MHD) power generation is a technique for electrical generation which passes a hot, ionized gas or liquid metal through a magnetic field. Such a high-temperature, one-stage conversion device has the potential of high-overall efficiencies. Though the concept of MHD generation has been known for over 100 years, it is only during the past decade that significant technological advances have produced systems which offer promise for use in the electric power field.

Three basic approaches to MHD generation are being explored--open-cycle, closed-cycle, and liquid metal systems.

The MHD open-cycle generator, used as a "topping unit" in conjunction with steam-turbine generators, appear to hold the most promise for MHD central-station power production in the near future. Overall system efficiency is expected to increase to a range of 50 to 60 percent over fossil fuel steam-electric plants. General application of coal-fired MHD topping units by the mid 1980's could effectively extend fossil fuel reserves and enhance the potential for use of coal for power generation. Since the MHD generator would require little cooling water, the combined MHD-steam units would require considerably less cooling water per megawatt of capacity than conventional fossil fueled or nuclear steam-electric units.

Before MHD can be utilized for central power station generation, there are many significant technological problems which must be solved. No economically practical system has yet been demonstrated for burning coal or coal-derived fuels. Designs to date have been small scale with short life-times and lower efficiencies than would be required for utility operation. There are problems of developing high-temperature electrodes, super-conductivity magnets, seed recovery systems, and coping with high temperature metal erosion and corrosion, etc. The high temperatures and gas passage time are conducive to fixation of nitrogen so there may be significant NO_x air quality problems.

Some environmental problems would be reduced due to decreased fossil fuel requirements of MHD generators, such as fossil fuel production impacts, thermal water discharges, and total noxious atmospheric emissions. There are environmental impacts inherent to MHD generation and to the total electrical energy demand increases which will create offsetting environmental problems. High temperature operations create specific NO_x emission problems. Coal powered MHD generators and increased power demands will lead in time to increased coal production with attendent environmental and worker health and safety problems. Transmission of electrical power or transportation of coal at some point in the fuel-generator-consumer chain will create land use, aesthetic, and associated environmental problems as discussed in previous sections.

While MHD appears to offer considerable future potential for coal-fired power generation, the technologic and economic uncertainties are still so great that it cannot now be considered as a viable alternative power source to geothermal development. (For additional detail, see Chapter IX of the Federal Power Commission's National Power Survey Report which is to be published about March 1972.)

FUEL CELLS

Fuel cells are electrochemical devices in which the chemical energy of fuel is converted continuously and directly to low-voltage direct current electricity. The basic process is similar to that of a battery except

that the fuel cell is an open system requiring a continuous supply of reactants for the production of electricity. Their potential advantages over more conventional energy conversion systems are their quietness, low temperature of operation, minimization of pollution, reliability, and greater efficiencies (up to 70 percent). Nearly one and one-half times more electrical energy can be obtained from a ton of coal in a fuel cell system than for a comparable amount burned in a modern, conventional power system.

Because of the current necessity for costly metal catalysts and reforming and fuel purification processes, the near future of fuel cells, even for small power units in a mass market, is remote. General application will be feasible only when efficient units capable of using common fuels are developed.

THERMIONIC GENERATION

When a metal is heated, a point is reached where its electrons acquire enough energy to overcome retarding forces at the surface of the metal and escape--boil off. When collected on another cooler metal surface, electrical energy can be generated by joining the two pieces of metal with an external circuit. Since thermionic generators are another type of heat engine, their efficiency theoretically is limited to 35-40 percent. At present, efficiencies ranging from 5 to 25 percent have been reported for test models. Commercial exploitation of the phenomenon awaits solution of difficult materials problems related to operations above 3000° F. and, in isotopic-fueled devices, radiation damage. The Federal Power Commission 1972 National Power Survey indicates that the concensus is that future efforts in thermionic development during the next decade will

be concentrated in space-oriented activities. The principal effort will be directed to the development of nuclear-fueled systems to be used as power sources for interplanetary expeditions. There is little likelihood of thermionics achieving commercial realization for large scale generation within the next several decades.

The state of development is not sufficiently advanced for an evaluation of potential environmental impacts. Since it is type of heat engine, the associated loss of heat is a potential source of thermal pollution. Heat sources of fossil or nuclear fuels also would have their relative environmental impacts.

TIDAL ENERGY

Tidal power is a hydroelectric-energy source similar to other water power sources except that it is derived from the alternate filling and emptying of a bay or estuary that can be enclosed by a dam. There are two major tidal power sites in the United States which have a significant potential for such development (Bernshlein, 1965). The Bay of Fundy, Maine with nine sites, including many on the Canadian side, has an average potential power capacity of approximately 29,000 Mw and Turnagain Bay in Cook Inlet, Alaska, has an estimated potential power capacity of 9,500 Mw. The distance from population centers makes the Turnagain Bay site doubtful from an economic standpoint. If the Bay of Fundy capacity was developed with half of the production going to Canada and half to the United States, the total addition to U. S. Capacity would be some 15,000 Mw. This would represent approximately 1.1 percent of generating needs by 1990.

The major technological problem associated with the development of tidal energy would be the need to develop turbines able to operate economically under low hydrostatic heads. (USDI, 1972). The Bay of Fundy potential of 15,000 Mw is comparable to the 7,000-20,000 Mw estimated geothermal potential; however it could hardly be considered substitutable owing to the distance from Fundy to the West Coast. The overall impact of tidal power on the U.S. energy supply would be minimal in that it does not represent a significant alternative to the need to develop other energy sources.

There would be significant environmental considerations associated with the damming and alternate filling and emptying of bay and estuary areas, such as impacts on sport and commercial fisheries, wildlife, water quality, recreation uses, other land uses, aesthetics, etc.

WIND ENERGY

The power in the wind is the result of a mass of air moving at speed in some particular direction. To capture such power requires placing in the path of the wind a machine which transfers the wind power to the machine (Golding, 1958). There is a wide range of estimates as to what the energy potential might be--one figure is 20,000,000 Mw at elevations low enough for extraction by aerogenerators (wind turbines). This figure reflects an ultimate potential, but it has little bearing on the degree to which this resource can be utilized. Economical power generation requires an average annual wind velocity of about 30 mph with nearly steady magnitude and direction and topography in which boundary-layer effects are minimal.

Although there are many locations that appear suitable for aerogenerators, their use would be contingent largely on the development of low-cost generators, a site amenable to low-cost installation, a favorable overall wind speed, and an electric grid capable of profitable use of interruptible power of this nature.

Wind energy does not appear to be a viable alternative to traditional large-scale energy sources at this time as a considerable amount of additional research and development is required. Even with reasonable success in such effort, favorable cost-benefit is questionable because of the high equipment costs and intermittent characteristics of the power source. However, there are those who feel that substantial electrical energy production is possible now from lower velocity winds and the use of technology developed in past research projects even though there has not been major activity toward commercial development of wind energy for several years. (Heronemus, 1972).

Since the use of the wind for power generation is a pollution-free source of electrical energy that would replace the need for fossil fuel or nuclear generation, there would be an environmental benefit that would be generally in direct ratio to the adverse environmental impacts of the alternative electrical energy generation source displaced.

A primary environmental disadvantage could be the aesthetic effect of a large number of towers with heights of as much as 1000 ft. topped with large generators turned by wind turbines with blades of 50 to 200 ft. in length, or possibly even larger, which would be at prominent locations.

Previous large scale efforts have failed due to structural factors, so tower structures probably would require heavy guying. There would be land surface impacts resulting from the construction and operation of numerous generator sites and access thereto. Since each tower would have to be serviced by transmission lines and related structures to connect the wind generation grid into power grids, there could be considerable environmental disturbance associated with the development and operation of such lines.

SOLAR ENERGY

Although the solar energy density is low, the United States land area intercepts each year about 600 times its total 1970 energy requirements. Such heat could be used for electricity generation, space heating, cooling, and processing of industrial materials. The electromagnetic properties of solar radiation produce photosynthetic coversion and storage of energy in plants and other photochemical reactions which also convert and store energy.

The number and range of potential solar applications are extensive but the present state of the art is such that energy collection efficiencies are low, and the requirements for energy storage resulting from the intermitteent nature of the source result in costs that are prohibitive for general use. A typical 2,000 Mw power plant operating in a 1,400 Btu/day solar climate would, with present technology, require 74 square miles of collector surface (assuming efficiency of conversion of solar energy to process heat is 30 percent and to electrical energy is 5 percent). The many square miles of collector surface that would be required for even a medium-sized power generation facility would have significant impact on the land area, its other use or resource values and on the general environment. There would

be a major aesthetic intrusion in desert areas which now are generally unmarred by man's activities.

Such large collector areas and low efficiencies make it unlikely that solar energy will have any significant impact as a large-scale source of power within the next 30 or more years as the economics are very unfavorable compared to many alternatives. Even a 300-percent increase in the solar cell efficiency would not result in power costs that would be economically acceptable for general use. A massive research and development effort over an extended period of time would be required to lower costs, increase conversion efficiency and to achieve acceptable system performance.

Examples of other types of solar generation potential include floating power plants which would use the solar-produced temperature differentials which exist between the upper and lower levels of Caribbean waters and the Gulf Stream. A second concept deals with the orbiting of space vehicles for the purpose of creating central power generation. Systems such as these have not yet been developed or tested so they do not represent viable energy source alternatives that can be considered at this time.

BIOLOGICAL ENERGY

Organic wastes in the United States are a potential source of energy of significant magnitude. Of the annual production which is excess of 2 billion tons, some 880 million tons is organic, moisture-and-ash-free material. Animal manure is the largest single organic waste; however, other agricultural wastes and urban refuse and commercial waste add significantly to the total. Bureau of Mines research (Appell and others, 1971) has shown that it is possible to convert such organic wastes to

oil with a potential of 1.25 barrels of oil per ton of waste. If all of this waste could be converted to oil, it would represent over 1.3 billion barrels of oil a year. This compares with a 1970 petroleum demand of 5.4 billion barrels. However, it must be recognized that even if this preliminary technology could be developed to commercial feasibility, only a fraction of the organic wastes could be collected with a reasonable amount of cost and effort for application of this process. Nevertheless, its use does have the potential of providing a significant supplemental source of oil. The process lends itself to essentially pollution-free operation while at the same time offering a solution to a portion of the problem of solid-waste disposal. The oil has a low-sulphur content and a high-heating value. If only half of the organic waste could be converted to oil, it could supply an amount equal to current volume of residual fuel oil now used for electrical generation.

Preliminary research has been done in closed, batch autoclaves. Currently, a continuous unit with a capacity of 20 pounds per hour is being operated.

Considerable additional work over a period of years will be required to move from the present early stage research to demonstration operations at a commercial scale to prove technological feasibility and to develop adequate economic data. No cost or estimate of probably commercial-scale production can be made at this time.

The process lends itself to implementation of a waste conversion process which will recycle waste to provide fuel resource values and, at the same time will greatly alleviate many of the critical solid

waste disposal situations confronting the Nation. Water quality problems associated with feedlot and agricultural wastes could be mitigated. The need for land fills or other volume forms of disposal would be greatly reduced as the solid residue from the process would consist of the mineral constituents in the original charge. Its quantity would be small and because it would be sterile, it would produce no problem as land fill material. Since the process produces a low-sulphur oil with high-heat value, it could replace the need for natural-oil production with a corresponding reduction in all of the related environmental hazards of such production.

It is doubtful if production of significant magnitude could be achieved by 1980 so, pending further research and development, it cannot be considered a viable alternative at this time.

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Limiting Energy Demand

An alternative to the implementation of a leasing program for geothermal steam could be a reduction in the demand for energy. A reduction in demand with respect to one form of energy consumption would tend to reduce overall energy demand, with the exception perhaps of transportation. Energy demand reductions could be accomplished by actions such as reduction in automobile horsepower, increased building insulation, increased mass transportation systems to offset individual car use, etc. Before any such actions could be put into effect, a host of legal, social, economic, environmental, and public acceptance factors must be considered.

The demand for energy in the United States has been increasing at an average rate of 3.1 percent annually for the last 20 years. Energy demand in the rest of the world has grown at a rate nearly double that of the United States in recent years.

Energy demand has been closely correlated with gross national product, which, in turn, is closely correlated with both population and per-capita income. The increasing use of energy has therefore been correlated with increasing affluence and a rising material standard of living. In part, perhaps, because the economic cost of energy has not taken full account of environmental costs and because supplies of resources have been ample, growth in energy demand has been little constrained by economic considerations.

Using as an example one for costs and a current base forecast (Bureau of Census, 1970, Series D) of population, the trend is as follows:

Year	(Million) Population	Selected estimates of total energy consumption (trillion Btu)	Per capita consumption (million Btu)
1970	204	68,810	337
1975	216	88,612	410
1985	240	133,396	556
2000	288	191,556	665

Clearly the increase in percapita consumption is far more important to growth in energy demand than the growth in population. At the extreme of replacement fertility and no net immigration (Bureau of Census, 1970, Series X), growth trends would be:

Year	(Million) Population	Selected estimates of total energy consumption (trillion Btu)	Per capita consumption (Million Btu)
1970	204	68,810	337
1975	214	88,560	410
1985	233	129,548	556
2000	256	170,240	665

The continued increase in population to the year 2000, despite a zero population growth rate, is due to the age distribution and consequent fertility expectations in the existing population.

Population growth trends are in a transitional phase: United States population growth rates appear to be declining even without government intervention.

Efforts at education and encouragement of voluntary family planning are policy options, but the above tables show that, even at the extreme of immediate zero population growth, the effect on total energy demand would not be great over the near term unless perceptive demand growth is slowed.

Reduction in demand through reduction in the growth of per capita consumption is possible. The Bureau of Census projections cited above envision a 22% increase per capita consumption by 1975 and a 65% increase by 1985, both relative to 1970. These growth rates could be lessened in two ways: (1) reducing the rate of growth of demand for the goods and services produced by the energy demanded, and (2) producing the demanded goods and services more efficiently.

Continued increased in material standard of living tend to be equated with increased number, variety, and size of objects which consume energy in their construction and operation: automobiles, aircraft, refrigerators, air conditioners, and the like. Transportation uses--primarily private automobiles--comprise 55 percent of current petroleum demand. Increases in size, performance, and amenities (such as automotive air conditioning) increase fuel consumption. Reduction in the rate of growth of per capita energy demand -- and especially of per capita petroleum demand -- could result from a trend toward smaller cars and increased use of mass transit. Greatly increased use of air conditioning in recent years has contributed to the rapid growth of electrical energy consumption; increased use of insulation could reduce energy requirements for operation.

Advances in technology offer promise of increasing the efficiency of extraction of energy from fuels. Examples include fuel cells, magnetohydrodynamics, and breeder reactors.

A major consideration in restricting demand for energy is the relationship between the cost involved in accomplishing such restriction and the environmental damage which would be prevented thereby. In general, the cost-benefit ratio of reducing energy demand would vary considerably depending upon the existence, the level, and the effectiveness of environmental protection measures adopted.

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PROPOSED UNIT PLAN REGULATIONS

APPENDIX H

TO

DRAFT ENVIRONMENTAL IMPACT STATEMENT

FOR THE

GEOTHERMAL LEASING PROGRAM

in compliance with

Section 102 (2) (c) of the National Environmental

Policy Act of 1969

Prepared by

U. S. Department of the Interior

May 1972

Code of Federal Regulations

Title 30 - Mineral Resources

Chapter II

Geological Survey

Part 271

Geothermal Resources

Unit Plan Regulations

Part 271 - Geothermal Resources Unit Plan Regulations (including suggested forms).

GENERAL PROVISIONS

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Authority. Section 18 of the Geothermal Steam Act of 1970 (84 Stat. 1566) (see 43 CFR Subpart 3244).

271.1 Introduction.

The regulations in this part prescribe the procedure to be followed and the requirements to be met by holders of Federal geothermal leases (see section 271.2d) and their representatives who wish to unite with each other, or jointly or separately with others, in collectively adopting and operating under a cooperative or unit plan for the development of any geothermal resources pool, field, or like area, or any part thereof. Such agreements may be initiated by lessees, or where in the interest of conserving natural resources they are deemed necessary they may be required by the Director.

271.2 Definitions.

The following terms, as used in this part or in any agreement approved under the regulations in this part, shall have the meanings here indicated unless otherwise defined in such agreement:

(a) Unit Agreement. An agreement or plan of development and operation for the production and utilization of separately owned interests in the geothermal resources made subject thereto as a single consolidated unit without regard to separate ownerships and which provides for the allocation of costs and benefits on a basis defined in the agreement or plan.

(b) Cooperative agreement. An agreement or plan of development and operations for the production and utilization of geothermal resources made subject thereto in which separate ownership units are independently operated without allocation of production.

(c) Agreement. For convenience, the term "agreement" as used in the regulations in this part refers to either a unit or a cooperative agreement as defined in paragraphs (a) and (b) of this section unless otherwise indicated.

(d) Geothermal lease. A lease issued under the act of December 24, 1970 (84 Stat. 1566), pursuant to the leasing regulations contained in 43 CFR Group 3200.

(e) Unit area. The area described in a unit agreement as constituting the land logically subject to development under such agreement.

(f) Unitized land. The part of a unit area committed to a unit agreement.

(g) Unitized substances. Deposits of geothermal resources recovered from unitized land by operation under and pursuant to a unit agreement.

(h) Unit operator. The person, association, partnership, corporation, or other business entity designated under a unit agreement to conduct operations on unitized land as specified in such agreement.

(i) Participating area. That part of a unit area to which production would be allocated in the manner described in the unit agreement, if all lands in the unit area were committed to the unit agreement.

(j) Working interest. The interest held in geothermal resources or in lands containing the same by virtue of a lease, operating agreement, fee title, or otherwise, under which, except as otherwise provided in a unit or cooperative agreement, the owner of such interest is vested with the right to explore for, develop, produce, and utilize such resources. The right delegated to the unit operator as such by the unit agreement is not to be regarded as a working interest.

(k) Secretary. The Secretary of the Interior or any person duly authorized to exercise powers vested in that officer.

(l) Director. The Director of the United States Geological Survey.

(m) Supervisor. The authorized representative of the Secretary of Interior under the administrative direction of the Director, Geological Survey, exercised through the Chief, Conservation Division, Geological Survey.

271.3 Designation of area.

An application for designation of an area as logically subject to development and/or operation under a unit or cooperative agreement may be filed, in triplicate, by any proponent of such an agreement through the Supervisor. Each copy of the application shall be accompanied by a map or diagram on a scale of not less than 1 inch to one mile, outlining the area sought to be designated under this section. The Federal, State, and privately

owned land should be indicated on said map by distinctive symbols or colors and Federal geothermal leases and lease applications should be identified by serial number. Geologic information, including the results of geophysical surveys, and such other information as may tend to show that unitization is necessary and advisable in the public interest should be furnished in triplicate. Geological and geophysical information and data so furnished will not be available for public inspection, as provided by 5 U. S. C. § 552(b), without the consent of the proponent. The application and supporting data will be considered by the Director and the applicant will be informed of the decision reached. The designation of an area, pursuant to an application filed under this section, shall not create an exclusive right to submit an executed agreement for such area, nor preclude the inclusion of such area or any part thereof in another unit area.

271.4 Preliminary consideration of agreements.

The form of unit agreement set forth in 271.12 is acceptable for use in unproved areas. The use of this form is not mandatory, but any proposed departure therefrom should be submitted with the application submitted under section 271.3 for preliminary consideration and for such revision as may be deemed necessary. In areas proposed for unitization in which a discovery of

geothermal resources has been made, or where a cooperative agreement is contemplated, the proposed agreement should be submitted with the application submitted under section 271.3 for preliminary consideration and for such revision as may be deemed necessary. The proposed form of agreement should be submitted in triplicate and should be plainly marked to identify the proposed variances from the form of agreement set forth in Section 271.12.

271.5 *State land.*

Where State-owned land is to be unitized, approval of the agreement by appropriate State officials should be obtained prior to its submission to the Department for approval of the executed agreement. When authorized by the laws of the State in which the unitized land is situated, provisions may be made in the agreement accepting statement to the extent that they are applicable to non-Federal unitized land.

271.6 *Qualifications of unit operator.*

A unit operator must qualify as to citizenship in the same manner as those holding interests in geothermal leases issued under the Geothermal Steam Act of 1970. The unit operator may be an owner of a working interest in the unit area or such other party as may be selected by the owners of working interests and approved by the Supervisor. The unit operator shall execute an acceptance of the duties and obligations imposed by the agreement. No designation of, or change in, a unit operator will become effective unless and until approved by the Supervisor, and no such approval will be granted unless the unit operator is deemed qualified to fulfill the duties and obligations prescribed in the agreement.

271.7 *Parties to unit or cooperative agreement.*

The owners of any rights, title, or interest in the geothermal resources deposits to be developed and operated under an agreement can be regarded as proper parties to a proposed agreement. All such owners must be invited to join as parties to the agreement. If any owner fails or refuses to join the agreement, the proponent of the agreement should declare this to the Supervisor and should submit evidence of efforts made to obtain joinder of such owner and the reasons for nonjoinder.

271.8 *Approval of an executed unit or cooperative agreement.*

(a) A duly executed unit or cooperative agreement will be approved by the Secretary, or his duly authorized representative, upon a determination that such agreement is necessary or advisable in the public interest and is for the purpose of properly conserving the natural resources. Such approval will be incorporated in a certificate appended to the agreement. No such agreement will be approved unless at least one of the parties is a holder of a Federal lease embracing lands being committed to the agreement and unless the parties signatory to the agreement hold sufficient interests in the area to give effective control of operations therein.

(b) Where a duly executed agreement is submitted for Departmental approval, a minimum of six signed counterparts should be filed. The same number of countparts should be filed for documents supplementing, modifying, or amending an agreement, including change of operator, designation of new operator, and notice of surrender, relinquishment, or termination.

(c) The address of each signatory party to the agreement should be inserted below the party's signature. Each signature should be attested by at least one witness, if not notarized. Corporate or other signatures made in a representative capacity must be accompanied by evidence of the authority of the signatories to act unless such evidence is already

a matter of record in the United States Geological Survey. (the parties may execute any number of counterparts of the agreement with the same force and effect as if all parties signed the same document, or may execute a ratification or consent in a separate instrument with like force and effect.).

(d) Any modification of an approved agreement will require approval of the Secretary or his duly authorized representative under procedures similar to those cited in subsection (a).

271.9 Filing of papers and number of counterparts.

(a) All proposals and supporting papers, instruments, and documents submitted under this part should be filed with the Supervisor, unless otherwise provided in this part or otherwise instructed by the Director.

(b) Plans of development and operation, plans of further development and operation, and proposed participating areas and revisions thereof should be submitted in quadruplicate.

(c) Each application for approval of a participating area, or revision thereof, should be accompanied by three copies of a substantiating geologic and engineering report, structure contour map or maps, cross-section or other pertinent data.

(d) Other instruments or documents submitted for approval should be submitted for approval in sufficient number to permit the approving official to return at least one approved counterpart.

271.10 Bonds.

In lieu of separate bonds required for each Federal lease committed to a unit agreement, the unit operator shall furnish and maintain a collective corporate surety bond or a personal bond conditioned upon faithful performance of the duties and obligations of the agreement and the terms of the leases subject thereto. Personal bonds shall be accompanied by a deposit of negotiable Federal securities in a sum equal at their par value to the amount of the bond and by a proper conveyance to the Secretary of full authority to sell such securities in case of default in the performance of the obligations assumed. The liability under the bond shall be for such amount as the Supervisor shall determine to be adequate to protect the interests of the United States and additional bond may be required whenever deemed necessary by the Supervisor. The bond may be filed with the manager of the district land office or the Supervisor, however, evidence must be furnished the Supervisor that such bond has been accepted by the Bureau of Land Management before operations will be authorized. A form of corporate surety bond is set forth in Sec. 271.15. In case of changes of unit operator, a new bond must be filed or a consent

of surety to the change in principal under the existing bond must be furnished.

271.11 Appeals.

Appeals may be taken in the manner provided in § 270.81 of this chapter from any decision, order or ruling issued under the regulation in this part, unless such decision, order or ruling was approved by the Secretary prior to the filing of the appeal.

271.12 Form of Unit Agreement for Unproved Areas.

UNIT AGREEMENT FOR THE DEVELOPMENT AND OPERATIONS OF THE

_____UNIT AREA, COUNTY OF_____

STATE OF_____, NO._____

UNIT AGREEMENT

FOR THE DEVELOPMENT AND OPERATION OF THE

_____ *Unit Area*

County of _____

State of _____

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_____ UNIT AGREEMENT

_____ COUNTY _____

This Agreement entered into as of the _____ day of _____, 19___, by and between the parties subscribing, ratifying, or consenting hereto, and herein referred to as the "parties hereto".

WITNESSETH:

Whereas the parties hereto are the owners of working, royalty, or other geothermal resources interests in land subject to this Agreement; and

Whereas the Geothermal Steam Act of 1970 (84 Stat. 1566), hereinafter referred to as the "Act", authorizes Federal lessees and their representatives to unite with each other, or jointly or separately with others, in collectively adopting and operating under a cooperative or unit plan of development or operation of any geothermal resources pool, field, or like area, or any part thereof, for the purpose of more properly conserving the natural resources thereof, whenever determined and certified by the Secretary of the Interior to be necessary or advisable in the public interest; and

Whereas the parties hereto hold sufficient interest in the _____ Unit Area covering the land herein described to effectively control operations therein; and

Whereas, it is the purpose of the parties hereto to conserve natural resources, prevent waste, and secure other benefits obtainable through development and operations of the area subject to this Agreement under the terms, conditions, and limitations herein set forth;

Now, Therefore, in consideration of the premises and the promises herein contained, the parties hereto commit to this agreement their respective interests in the below-defined Unit Area, and agree severally among themselves as follows:

ARTICLE I

ENABLING ACT AND REGULATIONS

1.1 The Act and all valid pertinent regulations, including operating and unit plan regulations, heretofore or hereafter issued thereunder are accepted and made a part of this agreement as to Federal lands.

1.2 As to non-Federal lands, the geothermal resources operating regulations in effect as of the effective date hereof governing drilling and producing operations, not inconsistent with the laws of the State in which the non-Federal land is located, are hereby accepted and made a part of this agreement.

ARTICLE II

DEFINITIONS

2.1 The following terms shall have the meanings here indicated:

(a) Geothermal lease. A lease issued under the act of December 24, 1970 (84 Stat. 1566), pursuant to the leasing regulations contained in 43 CFR Group 3200.

(b) Unit area. The area described in Article III of this Agreement.

(c) Unit Operator. The person, association, partnership, corporation, or other business entity designated under this Agreement to conduct operations on Unitized Land as specified herein.

(d) Participating area. That part of the Unit Area to which production would be allocated in the manner described in this Agreement, if all lands in the Unit Area were committed hereto.

(e) Working interest. The interest held in geothermal resources or in lands containing the same by virtue of a lease, operating agreement, fee title, or otherwise, under which, except as otherwise provided in this Agreement, the owner of such interest

is vested with the right to explore for, develop, produce and utilize such resources. The right delegated to the Unit Operator as such by this Agreement is not to be regarded as a Working Interest.

(f) Secretary. The Secretary of the Interior or any person duly authorized to exercise powers vested in that officer.

(g) Director. The Director of the United States Geological Survey.

(h) Supervisor. The authorized representative of the Secretary of Interior under the administrative direction of the Director, Geological Survey, exercised through the Chief, Conservation Division, Geological Survey.

ARTICLE III

UNIT AREA AND EXHIBITS

3.1 The area specified on the map attached hereto marked "Exhibit A" is hereby designated and recognized as constituting the Unit Area, containing _____ acres , more or less.

The above-described Unit Area shall when practicable be expanded to include therein any additional lands or shall be contracted to exclude lands whenever such expansion or contraction is deemed to be necessary or advisable to conform with the purposes of this Agreement.

3.2 Exhibit A attached hereto and made a part hereof is a map showing the boundary of the Unit Area, the boundaries and

identity of tracts and leases in said area to the extent known to the Unit Operator.

3.3 Exhibit B attached hereto and made a part hereof is a schedule showing to the extent known to the Unit Operator the acreage, percentage, and kind of ownership of geothermal resources interests in all lands in the Unit Area.

3.4 Exhibits A and B shall be revised by the Unit Operator whenever changes in the Unit Area render such revision necessary, or when requested by the Supervisor, and not less than five copies of the revised *Exhibits* shall be filed with the Supervisor.

ARTICLE IV

CONTRACTION AND EXPANSION OF UNIT AREA

4.1 Unless otherwise specified herein, the expansion and/or contraction of the Unit Area contemplated in Article 3.1 hereof shall be effected in the following manner:

(a) Unit Operator, on its own motion or on demand of the Director shall prepare a notice of proposed expansion or contraction describing the contemplated changes in the boundaries of the Unit Area, the reasons therefore, and the proposed effective date thereof, preferably the first day of a month subsequent to the date of notice.

(b) Said notice shall be delivered to the Supervisor, and copies thereof mailed to the last known address of each Working

Interest Owner, Lessee, and Lessor whose interests are affected, advising that 30 days will be allowed for submission to the Unit Operator of any objections.

(c) Upon expiration of the 30-day period provided in the preceding item (b) hereof, Unit Operator shall file with the Supervisor evidence of *mailing* of the notice of expansion or contraction and a copy of any objections thereto which have been filed with the Unit Operator, together with an application in sufficient number, for approval of such expansion or contraction and with appropriate joinders.

(d) After due consideration of all pertinent information, the expansion or contraction shall, upon approval by the Supervisor, become effective as of the date prescribed in the notice thereof.

4.2. Unitized Leases, insofar as they cover any lands which *any of*
are excluded from the Unit Area under/the provisions of *this Article IV*
may be maintained and continued in force and effect in accordance with the terms, provisions, and conditions contained in *and the*
the Act,/lease or leases and amendments thereto, except that operations and/or production under this Unit Agreement shall not serve to maintain or continue the excluded portion of any lease.

4.3 All quarter-quarter (1/4--1/4) sections of land, no part of which is entitled to be within a Participating Area on the fifth anniversary of the effective date of the initial Participating Area established under this Agreement, shall be eliminated automatically from this Agreement effective as of said fifth anniversary and such

lands shall no longer be a part of the Unit Area and shall no longer be subject to this Agreement unless diligent drilling operations are in progress on an exploratory well on said fifth anniversary, in which event such lands shall not be eliminated from the Unit Area for as long as exploratory drilling operations are continued diligently with not more than four (4) months time elapsing between the completion of one exploratory well and the commencement of the next exploratory well.

4.4 An exploratory well, for the purposes of this Article IV is defined as any well, regardless of surface location, projected for completion in a zone or deposit below any zone or deposit for which a Participating Area has been established and is in effect, or any well, regardless of surface location, projected for completion at a subsurface location under Unitized Lands not entitled to be within a Participating Area.

4.5 In the event an exploratory well is completed during the four (4) months immediately preceding the fifth anniversary of the initial Participating Area established under this Agreement, lands not entitled to be within a Participating Area shall not be eliminated from this Agreement on said fifth anniversary, provided the drilling of another exploratory well is commenced under an approved Plan of Operation within four (4) months after the completion of said well. In such event, the land not entitled to be in participation shall not be eliminated from the Unit Area so long as exploratory drilling operations are continued diligently with not more than four (4) months time elapsing between the completion of one exploratory well and the commencement of the next exploratory well.

4.6 With prior approval of the Supervisor, when warranted, a period of time in excess of four (4) months may be allowed to elapse between the completion of one well and the commencement of the next well without the automatic elimination of non-participating acreage.

4.7 Unitized lands proved productive by drilling operations which serve to delay automatic elimination of lands under this Article IV shall be incorporated into a Participating Area (or Areas) in the same manner as such lands would have been incorporated in such areas had such lands been proven productive during the year preceding said fifth anniversary.

4.8 In the event non-participating lands are retained under this Agreement after the fifth anniversary of the initial Participating Area as a result of *exploratory drilling operations*, all quarter-quarter (1/4--1/4) blocks of land no part of which is entitled to be within a Participating Area shall be eliminated automatically as of the 121 day, or such later date as may be established by the Supervisor, following the completion of the last well recognized as delaying such automatic elimination beyond the fifth anniversary of the initial Participating Area established under this Agreement.

ARTICLE V

UNITIZED LAND AND UNITIZED SUBSTANCES

5.1 All land committed to this Agreement shall constitute land referred to herein as "Unitized Land". All geothermal resources in and produced from any and all formations of the Unitized Land are unitized under the terms of this agreement and herein are called "Unitized Substances."

ARTICLE VI

UNIT OPERATOR

6.1 _____ is hereby designated as Unit Operator and by signature hereto as Unit Operator agrees and consents to accept the duties and obligations of Unit Operator for the discovery, development, production, *distribution* and utilization of Unitized Substances as herein provided. Whenever reference is made herein to the Unit Operator, such reference means the Unit Operator acting in that capacity and not as an owner of interest in Unitized Substances, and the term "Working Interest Owner" when used herein shall include or refer to Unit Operator as the owner of a Working Interest when such an Interest is owned by it.

ARTICLE VII

RESIGNATION OR REMOVAL OF UNIT OPERATOR

7.1 Prior to the establishment of a Participating Area, hereunder, Unit Operator shall have the right to resign. Such resignation shall not become effective so as to release Unit Operator from the duties and obligations of Unit Operator or terminate Unit

Operators rights, as such, for a period of six (6) months after notice of its intention to resign has been served by Unit Operator on all Working Interest Owners and the Supervisor, *nor* until all wells then drilled hereunder are placed in a satisfactory condition for suspension or abandonment whichever is required by the Supervisor, unless a new Unit Operator shall have been selected and approved and shall have taken over and assumed the duties and obligations of Unit Operator prior to the expiration of said period.

7.2 After the establishment of a Participating Area hereunder Unit Operator shall have the right to resign in the manner and subject to the limitations provided in 7.1 above.

7.3 The Unit Operator may, upon default or failure in the performance of its duties or obligations hereunder, be subject to removal by the same percentage vote of the owners of Working Interests as herein provided for the selection of a new Unit Operator. Such removal shall be effective upon notice thereof to the Supervisor.

7.4 The resignation or removal of Unit Operator under this Agreement shall not terminate its right, title, or interest as the owner of a Working Interest or other interest in Unitized Substances, but upon the resignation or removal of Unit Operator becoming effective, such Unit Operator shall deliver possession of all wells, equipment, material, and appurtenances used in conducting the unit operations to the new duly qualified successor Unit Operator or *if no such new unit operator is elected, to the common agent appointed to represent the Working Interest Owners in any action taken hereunder to be used for the purpose of conducting operations hereunder.*

7.5 In all instances of resignation or removal, until a successor Unit Operator is selected and approved as hereinafter provided, the Working Interest Owners shall be jointly responsible for performance of the duties and obligations of Unit Operator, and shall not later than 30 days before such resignation or removal becomes effective appoint a common agent to represent them in any action to be taken hereunder.

7.6 The resignation of Unit Operator shall not release Unit Operator from any liability for any default by it hereunder occurring prior to the effective date of its resignation.

ARTICLE VIII

SUCCESSOR UNIT OPERATOR

8.1 If, prior to the establishment of a Participating Area hereunder, the Unit Operator shall resign as Operator, or shall be removed as provided in Article VII, a successor Unit Operator may be selected by vote or the owners of a majority of the Working Interests in Unitized Substances, based on their respective shares, on an acreage basis, in the Unitized Land.

8.2 If, after the establishment of a Participating Area hereunder, the Unit Operator shall resign as Unit Operator, or shall be removed as provided in Article VII, a successor Unit Operator may be selected by vote of the owners of a majority of the Working Interests in Unitized Substances, based on their respective shares, on a participating acreage basis. Provided, that, if a majority but less than 60 percent of the Working Interest in the Participating Lands is owned by the party to this agreement, a concurring vote of one or more additional Working Interest Owners

owning 10 percent or more of the Working Interest in the Participating Land shall be required to select a new Unit Operator.

8.3 The selection of a successor Unit Operator shall not become effective until

(a) The Unit Operator so selected shall accept in writing the duties, obligations and responsibilities of the Unit Operator, and

(b) The selection shall have been approved by the Supervisor.

8.4 If no successor Unit Operator is selected and qualified as herein provided, the Director at his election may declare this Agreement terminated.

ARTICLE IX

ACCOUNTING PROVISIONS AND UNIT OPERATING AGREEMENT

9.1 Costs and expenses incurred by Unit Operator in conducting unit operations hereunder shall be paid and apportioned among and borne by the owners of Working Interests; all in accordance with the agreement or agreements entered into by and between the Unit Operator and the *owners* of Working Interests, *whether one or more, separately* or collectively.

9.2 Any agreement or agreements entered into between the Working Interest Owners and the Unit Operator as provided in this Article, whether one or more, are herein referred to as the "Unit Operating Agreement".

9.3 The Unit Operating Agreement shall provide the manner in which the Working Interest Owners shall be entitled to receive their respective share of the benefits accruing hereto in conformity with their underlying operating agreements, leases, or other contracts, and such other rights and obligations, as between Unit Operator and the Working Interest Owners.

9.4 Neither the Unit Operating Agreement nor any amendment thereto shall be deemed either to modify any of the terms and conditions of this Agreement or to relieve the Unit Operator of any right or obligation established under this Agreement.

9.5 In case of any inconsistency or conflict between this Agreement and the Unit Operating Agreement, this Agreement shall govern.

9.6 Three true copies of any Unit Operating Agreement executed pursuant to this Article IX shall be filed with the Supervisor prior to approval of this Agreement.

ARTICLE X

RIGHTS AND OBLIGATIONS OF UNIT OPERATOR

10.1 Subject to the consent and approval of a Plan of Operation by the Supervisor, the right, privilege, and duty of exercising any and all rights of the parties hereto which are necessary or convenient for prospecting, producing, distributing and/or utilizing Unitized Substances are hereby delegated to, and shall be exercised by, the Unit Operator as provided in this Agreement.

10.2 Upon request by Unit Operator, acceptable evidence of title to geothermal resources interests in the Unitized Land shall be deposited with the Unit Operator, and together with this Agreement shall constitute and define the rights, privileges, and obligations of Unit Operator.

10.3 Nothing in this Agreement shall be construed to transfer title to any land or to any lease or operating agreement, it being understood that the Unit Operator, in its capacity as Unit Operator shall exercise the rights of possession and use vested in the parties hereto only for the purposes specified in this Agreement.

10.4 The Unit Operator shall take such measures as the Supervisor deems appropriate and adequate to prevent drainage of Unitized Substances from Unitized Land by wells on land not subject to this Agreement.

10.5 The Director is hereby vested with authority to alter or modify from time to time, in his discretion, the rate of prospecting and development and the quantity and rate of production under this Agreement.

ARTICLE XI

PLAN OF OPERATION

11.1 Concurrently with the submission of this Agreement for approval, Unit Operator shall submit an acceptable initial Plan of Operation. Said plan shall be as complete and adequate as the Supervisor may determine to be necessary for timely exploration and/or development and to ensure proper protection of the environment and conservation of the natural resources of the Unit Area.

11.2 Prior to the expiration of the initial Plan of Operation, or any subsequent Plan of Operation, Unit Operator shall submit for approval of the Supervisor an acceptable *subsequent* Plan of Operation for the Unit Area which, when approved by the Supervisor, shall constitute the exploratory and/or development drilling and operating obligations of Unit Operators under this Agreement for the period specified therein.

11.3 Any Plan of Operation submitted hereunder shall

(a) specify the number and locations of any wells to be drilled and the proposed order and time for such drilling, and

(b) to the extent practicable, specify the operating practices regarded as necessary and advisable for proper conservation of natural resources and protection of the environment.

11.4 The Plan of Operation submitted concurrently with this Agreement for approval shall prescribe that within six *(6)* months after the effective date hereof, the Unit Operator shall begin to drill an adequate test well at a location approved by the Supervisor, unless on such effective date a well is being drilled conformably with the terms, hereof, and thereafter continue such drilling diligently until the _____formation has been tested or until at a lesser depth unitized substances shall be discovered which can be produced in paying quantities (to wit: quantities sufficient to repay the costs of drilling, completing, and producing operations, with a reasonable profit) or the Unit Operator

shall at any time establish to the satisfaction of the Supervisor that further drilling of said well would be unwarranted or impracticable, provided, however, that Unit Operator shall not in any event be required to drilling said well to a depth in excess of _____ feet.

The initial Plan of Operation and/or subsequent Plans of Operation submitted under this Article shall provide that the Unit Operator shall initiate a continuous drilling program providing for drilling of no less than one well at a time, and allowing no more than six (6) months time to elapse between completion of one well and the beginning of the next well, until a well capable of producing Unitized Substances in paying quantities is completed to the satisfaction of the Supervisor or until it is reasonably proved that the Unitized Land is incapable of producing Unitized Substances in paying quantities in the formations drilled under this Agreement.

11.6 When warranted by unforeseen circumstances, the Supervisor may grant a single extension of any or all of the critical dates for exploratory drilling operations cited in the initial or subsequent Plans of Operation. No such extension shall exceed a period of four (4) months for each well, required by the initial Plan of Operation.

11.7 Until there is actual production of Unitized Substances, the failure of Unit Operator to timely drill any of the wells provided for in Plans of Operation required under this Article XI or to timely submit an acceptable subsequent Plan of Operation , shall,

after notice of default or notice of prospective default to Unit Operator by the Supervisor and after failure of Unit Operator to remedy any actual default within a reasonable time (as determined by the Supervisor), result in automatic termination of this Agreement effective as of the date of the default, *as determined by the Supervisor.*

11.8 Separate Plans of Operations may be submitted for separate productive zones, subject to the approval of the *Supervisor.* Also subject to the approval of the Supervisor, Plans of Operation shall be modified or supplemented when necessary to meet changes in conditions or to protect the interest of all parties to this Agreement.

ARTICLE XII

PARTICIPATING AREAS

12.1 Prior to the commencement of production of Unitized Substances, the Unit Operator shall submit for approval by the Supervisor a schedule (or schedules) of all land then regarded as reasonably proved to be productive from a pool or deposit discovered or developed; all lands in said schedule (or schedules), on approval of the Supervisor, *will* constitute a Participating Area (or Areas) effective as of the date production commences or the effective date of this Unit Agreement, whichever is later. Said schedule (or schedules) shall also set forth the percentage of Unitized Substances to be allocated, as herein provided, to each tract in the Participating *Area* (or Areas) so established and shall govern the allocation of production commencing with the effective date of the Participating Area.

shall
12.2 A separate Participating Area / be established for each separate pool or deposit of Unitized Substances or for any group thereof which is produced as a single pool or deposit and any two or more Participating Areas so established may be combined into one, on approval of the Supervisor. The effective date of any Participating Area established after the commencement of actual production of Unitized Substances shall be the first of the month in which is obtained the knowledge or information on which the establishment of said Participating Area is predicated provided, however, that a more appropriate effective date may be used if justified by the Unit Operator and approved by the Supervisor.

12.3 Any Participating Area (or Areas) established under 12.1 or 12.2 above shall, subject to the approval of the Supervisor, be revised from time to time to include additional land then regarded as reasonably proved to be productive from the pool or deposit for which the Participating Area was established or to include lands necessary to unit operations, or to exclude land then regarded as reasonably proved not to be productive from the pool or deposit for which the Participating Area was established or to exclude land not necessary to unit operations and the schedule (or schedules) of allocation percentages shall be revised accordingly.

12.4 Subject to the limitation cited in 12.1 hereof, the effective date of any revision of a Participating Area established under Articles 12.1 or 12.2 shall be the first of the month in which is obtained the

knowledge or information on which such revision is predicated, provided, however, that a more appropriate effective date may be used if justified by the Unit Operator and approved by the Supervisor.

12.5 No land shall be excluded from a Participating Area on account of depletion of the Unitized Substances, except that any Participating Area established under the provisions of this Article XII shall terminate automatically whenever all operations are abandoned in the pool or deposit for which the Participating Area was established.

12.5 Nothing herein contained shall be construed as requiring any retroactive adjustment for production obtained prior to the effective date of the revision of a Participating Area.

ARTICLE XIII

ALLOCATION OF UNITIZED SUBSTANCES

13.1 All Unitized Substances produced from a Participating Area, established under this Agreement, shall be deemed to be produced equally on an acreage basis from the several tracts of Unitized Land within the Participating Area established for such production.

13.2 For the purpose of determining any benefits accruing under this Agreement, each Tract of Unitized Land shall have allocated to it such percentage of said production as the number of acres in the Tract included in the Participating Area bears to the total number of acres of Unitized Land in said Participating Area.

13.3 Allocation of production hereunder for purposes other than for settlement of the royalty obligations of the respective Working Interest Owners, shall be on the basis prescribed in the Unit Operating Agreement whether in conformity with the basis of allocation set forth above or otherwise.

13.4 The Unitized Substances produced from a Participating Area shall be allocated as provided herein regardless of whether any wells are drilled on any particular part or tract of said Participating Area.

ARTICLE XIV

RELINQUISHMENT OF LEASES

14.1 Pursuant to the provisions of the Federal leases and 43 CFR 3245.1, a lessee of record shall, subject to the provisions of the Unit Operating Agreement, have the right to relinquish any of its interests in leases committed hereto, in whole or in part; provided, that no relinquishment shall be made of interests in land within a Participating Area without the prior approval of the Director.

14.2 A Working Interest Owner may exercise the right to surrender, when such right is vested in it by any non-Federal lease, sublease, or operating agreement, provided that each party who will or might acquire the Working Interest in such lease by such surrender or by forfeiture is bound by the terms of this Agreement, and further provided that no such relinquishment shall be made of land within a Participating Area without the prior written consent of the non-Federal Lessor.

14.3 If as the result of relinquishment, surrender, or forfeiture the Working Interests become vested in the fee owner or lessor of the Unitized Substances, such owner may:

(1) Accept those Working Interest rights and obligations subject to this Agreement and the Unit Operating Agreement; or

(2) Lease the portion of such land as is included in a Participating Area established hereunder, subject to this Agreement and the Unit Operating Agreement; and provide for the independent operation of any part of such land that is not then included within a Participating Area established hereunder.

14.4 If the fee owner or lessor of the Unitized Substances does not, (1) accept the Working Interest rights and obligations subject to this Agreement and the Unit Operating Agreement, or (2) lease such lands as provided in 14.3 above within six (6) months after the relinquished, surrendered, or forfeited Working Interest becomes vested in said fee owner or lessor, the Working Interest benefits and obligations accruing to such land under this Agreement and the Unit Operating Agreement shall be shared by the owners of the remaining unitized Working Interests in accordance with their respective Working Interest ownerships, and such owners of Working Interests shall compensate the fee owner or lessor of Unitized Substances in such lands by paying sums equal to the rentals, minimum royalties, and royalties applicable to such lands under the lease or leases in effect when the Working Interests were relinquished, surrendered, or forfeited.

14.5 Subject to the provisions of 14.4 above, an appropriate accounting and settlement shall be made for all benefits accruing to or payments and expenditures made or incurred on behalf of any surrendered or forfeited Working Interest subsequent to the date of surrender or forfeiture, and payment of any moneys found to be owing by such an accounting shall be made as between the parties within thirty (30) days.

14.6 In the event no Unit Operating Agreement is in existence and a mutually acceptable agreement cannot be consummated between the proper parties, the Supervisor may prescribe such reasonable and equitable conditions of agreement as he deems warranted under the circumstances.

14.7 The exercise of any right vested in a Working Interest Owner to reassign such Working Interest to the party from whom obtained shall be subject to the same conditions as set forth in this Article XIV in regard to the exercise of a right to surrender.

ARTICLE XV

RENTALS AND MINIMUM ROYALTIES

15.1 Any unitized lease on non-Federal land containing provisions which would terminate such lease unless drilling operations are commenced upon the land covered thereby within the time therein specified or rentals are paid for the privilege of deferring such drilling operations, the rentals required thereby shall, notwithstanding any other provisions of this Agreement, be deemed to accrue as to the portion of the lease not included within a Participating Area and become payable during the term thereof as extended by this Agreement, and until the required drillings are commenced upon the land covered thereby.

15.2 Rentals are payable on Federal leases on or before the anniversary date of each lease year; minimum royalties accrue from the anniversary date of each lease year and are payable at the end of the lease year.

15.3 Beginning with the lease year commencing on or after _____ and for each lease year thereafter, rental or minimum royalty for lands of the United States subject to this Agreement shall be made on the following basis:

(a) An advance annual rental in the amount prescribed in unitized Federal leases, in no event creditable against production royalties, shall be paid for each acre or fraction thereof which is not within a Participating Area.

(b) A minimum royalty shall be charged at the beginning of each lease year (such minimum royalty to be due as of the last day of the lease year and payable within thirty (30) days thereafter) of $2.00 an acre or fraction thereof, for all Unitized Acreage within a Participating Area as of the beginning of the lease year. If there is production during the lease year the deficit if any, between the actual royalty paid and the minimum royalty prescribed herein shall be paid.

15.4 Rental or minimum royalties due on leases committed hereto shall be paid by Working Interest Owners responsible therefor under existing contracts, laws, and regulations, or by the Unit Operator.

15.5 Settlement for royalty interest shall be made by Working Interest Owners responsible therefor under existing contracts, laws, and regulations, or by the Unit Operator, on or before the last day of each month for Unitized Substances produced during the preceding calendar month.

15.6 Royalty due the United States shall be computed as provided in the operating regulations and paid in value as to all Unitized Substances on the basis of the amounts thereof allocated to unitized Federal land as provided herein at the royalty rate or rates specified in the respective Federal leases.

15.7 Nothing herein contained shall operate to relieve the lessees of any land from their respective lease obligations for the payment of any rental, minimum royalty, or royalty due under their leases.

ARTICLE XVI

OPERATIONS ON NONPARTICIPATING LAND

16.1 Any party hereto owning or controlling the Working Interest in any Unitized Land having thereon a regular well location may, with the approval of the Supervisor and at such party's sole risk, costs, and expense, drill a well to test any formation of deposit for which a Participating Area has not been established or to test any formation or deposit for which a Participating Area has been established if such location is not within said Participating Area, unless within 30 days of receipt of notice from said party of his intention to drill the well, the Unit Operator elects and commences to drill such a well in like manner as other wells are drilled by the Unit Operator under this Agreement.

16.2 If any well drilled by a Working Interest Owner other than the Unit Operator proves that the land upon which said well is situated may properly be included in a Participating Area, such Participating Area shall be established or enlarged as provided in this Agreement and the well shall thereafter be operated by the Unit Operator in accordance with the terms of this Agreement and the Unit Operating agreement.

ARTICLE XVII

LEASES AND CONTRACTS CONFORMED AND EXTENDED

17.1 The terms, conditions, and provisions of all leases, subleases, and other contracts relating to exploration, drilling, development, or utilization of geothermal resources on lands committed to this

Agreement, are hereby expressly modified and amended only to the extent necessary to make the same conform to the provisions hereof, otherwise said leases, subleases, and contracts shall remain in full force and effect.

17.2 The parties hereto consent that the Secretary shall, by his approval hereof, modify and amend the

Federal leases committed hereto and the regulations in respect thereto to the extent necessary to conform said leases and regulations to the provisions of this Agreegment.

17.3 The development and/or operation of lands subject to this Agreement under the terms hereof shall be deemed full performance of any obligations for development and operation with respect to each and every separately owned tract subject to this Agreement, regardless of whether there is any development of any particular tract of the Unit Area.

17.4 Drilling and/or producing operations performed hereunder upon any tract of Unitized Lands will be accepted and deemed to be performed upon and for the benefit of each and every tract of Unitized Land.

17.5 Suspension of operations and/or production on all Unitized Lands pursuant to direction or consent of the Secretary or his duly authorized representative shall be deemed to constitute such suspension pursuant to such direction or consent as to each and every tract of Unitized Land. A suspension of operations and/or production limited to specified lands shall be applicable only to such lands.

17.6 Subject to the provisions of Article XV hereof and 17.10 of this Article, each lease, sublease, or contract relating to the exploration, drilling, development, or utilization of geothermal resources of lands other than those of the United States committed to this Agreement, is hereby extended beyond any such term so provided therein so that it shall be continued for and during the term of this Agreement.

17.7 Subject to the lease renewal and the readjustment provision of the Act, any Federal lease committed hereto may, as to the Unitized Lands, be continued for the term so provided therein, or as extended by law. This subsection shall not operate to extend any lease or portion thereof as to lands excluded from the Unit Area by the contraction thereof.

17.8 Each sublease or contract relating to the operations and development of Unitized Substances from lands of the United States committed to this Agreement shall be continued in force and effect for and during the term of the underlying lease.

17.9 Any Federal lease heretofore or hereafter committed to any such unit plan embracing lands that are in part within and in part outside of the area covered by any such plan shall be segregated into separate leases as to the lands committed and the lands not committed as of the effective date of unitization.

17.10 Any lease, other than a Federal lease, having only a portion of its land committed hereto shall be segregated as to the portion committed and the portion not committed, and the provisions of such lease shall apply separately to such segregated portions commencing as of the effective date hereof. In the event any such lease provides for a lump-sum rental payment, such payment shall be prorated between the portions so segregated in proportion to the acreage of the respective tracts.

17.11 Upon termination of this Agreement, the leases covered hereby may be maintained and continued in force and effect in accordance with the terms, provisions, and conditions of the Act, the lease or leases, and amendments thereto.

ARTICLE XVIII

EFFECTIVE DATE AND TERM

18.1 This Agreement shall become effective upon approval by the Secretary or his duly authorized representative and shall terminate five (5) years from said effective date unless,

(a) Such date of expiration is extended by the Director, or

(b) Unitized Substances are produced or utilized in commercial quantities in which event this Agreement shall continue for so long as Unitized Substances are produced or utilized in commercial quantities, or

(c) This Agreement is terminated prior to the end of said five (5) year period as heretofore provided.

18.2 This Agreement may be terminated at any time by the owners of a majority of the Working Interests, on an acreage basis, with the approval of the Supervisor. Notice of any such approval shall be given by the Unit Operator to all parties hereto.

ARTICLE XIX

APPEARANCES

19.1 Unit Operator shall, after notice to other parties affected, have the right to appear for and on behalf of any and all interests affected hereby before the Department of the Interior, and to appeal from decisions, orders or rulings issued under the regulations of said Department, or to apply for relief from any of said regulations or in any proceedings relative to operations before the Department of the Interior or any other legally constituted authority; provided, however, that any interested parties shall also have the right, at its own expenses, to be heard in any such proceeding.

ARTICLE XX

NO WAIVER OF CERTAIN RIGHTS

20.1 Nothing contained in this Agreement shall be construed as a waiver by any party hereto of the right to assert any legal or constitutional right or defense pertaining to the validity or invalidity of any law of the United States, or regulations issued thereunder, in any way affecting such party or as a waiver by any such party of any right beyond his or its authority to waive.

ARTICLE XXI

UNAVOIDABLE DELAY

21.1 The obligations imposed by this Agreement requiring Unit Operator to commence or continue drilling or to produce or utilize Unitized Substances from any of the land covered by this Agreement, shall be suspended while, but only so long as, Unit Operator, despite the exercise of due care and diligence, is prevented from complying with such obligations, in whole or in part, by strikes, Acts of God, Federal or other applicable law, Federal or other authorized governmental agencies, unavoidable accidents, uncontrollable delays in transportation, inability to obtain necessary materials in open market, or other matters beyond the reasonable control of Unit Operator, whether similar to matters herein enumerated or not.

21.2 No unit obligation which is suspended under this section shall become due less than thirty (30) days after it has been determined that the suspension is no longer applicable.

21.3 Determination of creditable "Unavoidable Delay" time shall be made by the Unit Operator subject to approval of the Supervisor.

ARTICLE XXII

POSTPONEMENT OF OBLIGATIONS

22.1 Notwithstanding any other provisions of this Agreement, the Director, on his own initiative or upon appropriate justification by Unit Operator, may postpone any obligaton established by and under this Agreement to commence or continue drilling or to operate on or produce Unitized Substances from lands covered by this *Agreement* when in his judgement, circumstances warrant such action.

ARTICLE XXIII

NONDISCRIMINATION

23.1 In connection with the performance of work under this Agreement, the Operator agrees to comply with all of the provisions of Section 202(1) to (7) inclusive, of Executive Order 11246 (30 F.R. 12319), which are hereby incorporated by reference in this Agreement.

ARTICLE XXIV

COUNTERPARTS

24.1 This Agreement may be executed in any number of counterparts no one of which needs to be executed by all parties, or may be ratified or consented to by separate instruments in writing specifically referring hereto, and shall be binding upon all parties who have executed such a counterpart, ratification or consent hereto, with the same force and effect as if all such parties had signed the same document.

ARTICLE XXV

SUBSEQUENT JOINDER

25.1 If the owner of any substantial interest in *geothermal resources under a tract* within the Unit Area fails or refuses to subscribe or consent to this Agreement, the owner of the Working Interest in that tract may withdraw said tract from this Agreement by written notice delivered to the Supervisor and the Unit Operator prior to the approval of this Agreement by the Supervisor.

25.2 Any geothermal resources interests in lands within the Unit Area not committed hereto prior to approval of this Agreement may thereafter be committed by the owner or owners thereof subscribing or consenting to this Agreement, and, if the interest is a Working Interest, by the owner of such interest also subscribing to the Unit Operating Agreement.

25.3 After operations are commenced hereunder, the right of subsequent joinder, as provided in this Article XXV, by a working Interest Owner is subject to such requirements or approvals, if any, pertaining to such joinder, as may be provided for in the Unit Operating Agreement. Joinder to the Unit Agreement by a Working Interest Owner, at any time, must be accompanied by appropriate joinder to the Unit Operating Agreement, if more than one committed Working Interest Owner is involved, in order for the interest to be regarded as committed to this Unit Agreement.

25.4 After final approval hereof, joinder by a non-working interest owner must be consented to in writing by the Working Interest Owner committed hereto and responsible for the payment of any benefits that may accrue hereunder in behalf of such non-working interest. A non-working interest may not be committed to this Agreement unless the corresponding Working Interest is committed hereto.

25.5 Except as may otherwise herein be provided, subsequent joinders to this Agreement shall be effective as of the first day of the month following the filing with the Supervisor of duly executed counterparts of all or any papers necessary to establish effective commitment of any tract to this Agreement unless objection to such joinder is duly made within sixty (60) days by the Supervisor.

ARTICLE XXVI

COVENANTS RUN WITH THE LAND

26.1 The covenants herein shall be construed to be covenants running with the land with respect to the interest of the parties hereto and their successors in interest until this Agreement terminates, and any grant, transfer, or conveyance, of interest in land or leases subject hereto shall be and hereby is conditioned upon the assumption of all priviledges and obligations hereunder by the grantee, transferee, or other successor in interest.

26.2 No assignment or transfer of any Working Interest or other interest subject hereto shall be binding upon Unit Operator until the first day of the calendar month after Unit Operator is furnished with the original, photostatic, or certified copy of the instrument of transfer.

ARTICLE XXVII

NOTICES

27.1 All notices, demands or statements required hereunder to be given or rendered to the parties *hereto shall be deemed fully* given if given in writing and personally delivered to the party or sent by postpaid registered or certified mail, addressed to such party or parties at their respective addresses set forth in connection with the signatures hereto or to the ratification or consent hereof or to such other address as any such party may have furnished in writing to party sending the notice, demand or statement.

ARTICLE XXVIII

LOSS OF TITLE

28.1 In the event title to any tract of Unitized Land shall fail and the true owner cannot be induced to join in this Agreement, such tract shall be automatically regarded as not committed hereto and there shall be such readjustment of future costs and benefits as may be required on account of the loss of such title.

28.2 In the event of a dispute as to title as to any royalty, Working Interest, or other interests subject hereto, payment or delivery on account thereof may be withheld without liability for interest until the dispute is finally settled; provided, that, as to Federal land or leases, no payments of funds due the United States shall be withheld, but such funds shall be deposited as directed by the Supervisor to be held as unearned money pending final settlement of the title dispute, and then applied as earned or returned in accordance with such final settlement.

ARTICLE XXIX

TAXES

29.1 The Working Interest Owners shall render and pay for their accounts and the accounts of the owners of non-working interests all valid taxes on or measured by the Unitized Substances in and under or that may be produced, gathered, and sold or utilized from the land subject to this Agreement after the effective date hereof.

29.2 The Working Interest Owners on each tract may charge a proper proportion of the taxes paid under 29.1 hereof to the owners of non-working interests in said tract, and may reduce the allocated share of each royalty owner for taxes so paid. No taxes shall be charged to the United States or the State of _____ or to any lessor who has a contract with his lessee which requires the lessee to pay such taxes.

ARTICLE XXX

RELATION OF PARTIES

30.1 It is expressly agreed that the relation of the parties hereto is that of independent contractors and nothing in this Agreement contained, expressed, or implied, nor any operations conducted hereunder, shall create or be deemed to have created a partnership or association between the parties hereto or any of them.

ARTICLE XXXI

SPECIAL FEDERAL LEASE STIPULATIONS AND/OR CONDITIONS

31.1 Nothing in this Agreement shall modify special lease stipulations and/or conditions applicable to lands of the United States. No modification of the conditions necessary to protect the lands or functions of lands under the jurisdiction of any Federal agency is authorized except with prior consent in writing whereby the authorizing official specifies the modification permitted.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed and have set opposite their respective names the date of execution.

WITNESSES:

UNIT OPERATOR
(AS UNIT OPERATOR & AS WORKING INTEREST OWNER)

_____

_____

By _____

WITNESSES:

WORKING INTEREST OWNERS

_____

_____

By _____

_____

_____

By _____

_____

_____

By _____

WITNESSES:

OTHER INTEREST OWNERS

_____

_____

By _____

_____

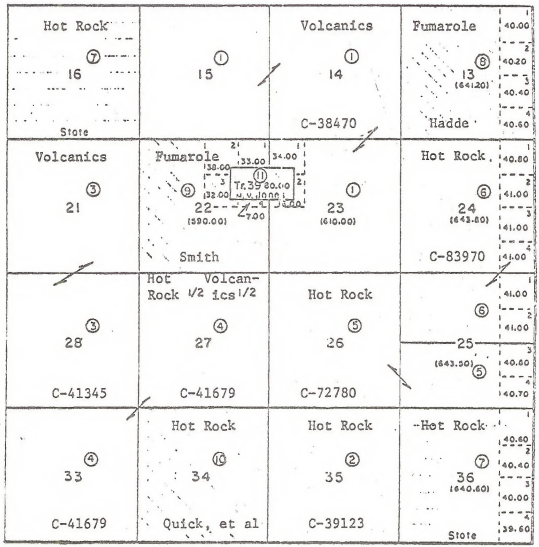
_____

By _____

271.13 Sample Form of Exhibit A.

Exhibit A
BIG VAPOR UNIT AREA
T. 13 N., R. 10 W., M.D.M., Calif.

R. 10 W.



① Means tract number as listed on Exhibit B

PUBLIC LAND

STATE LAND

PATENTED LAND

271.14 Sample Form of Exhibit B

Exhibit B -- Big Vapor Unit Area, Napa County, California, T. 13 N., R. 10 W.

Tract No.	Description of land	Number of acres	Ser. no.&Exp. date of lease	Basic royalty and Ownership percentage		Lessee of Record	Working interest and percentage	
	Federal Land		Calif. Serials					
1.	Sec.14: All Sec.15: All Sec.23: Lots 1, 2, S½, NE¼, E½NW¼	1,890.00	38470 7-81-82	U. S.:	All	Volcanics Inc.	Volcanics Inc:	All
2	Sec.35: All	640.00	39123 7-31-82	U. S.:	All	D. H. Boiler	Hot Rock Co:	All
3	Sec.21: All Sec.28: All	1,280.00	41345 7-31-82	U. S.:	All	C. S. Waters-50% D. F. Mann-50%	Volcanics Co.: Hot Rock Co.:	50% 50%
4.	Sec.27: All Sec.33: All	1,280.00	41679	U. S.:	All	H. C. Pipes	Fumarole Ltd:	All
5	Sec.26: All Sec.25: S½	961.50	71278 9-31-82	U. S.:	All	Hot Rock Co.	Hot Rock Co:	All
6	Sec.24: All Sec.25: N½	965.80	83970 Application	U. S.:	All	H. C. Pipes	Hot Rock Co:	All
	6 Federal tracts 7,017.30 acres or 68.47% of unit area.							
	Calif. State Land							
7	Sec.16: All Sec.36: All	1,280.60	65-67430	State of Calif.:	All	Hot Rock Co.	Hot Rock Co.:	All
	1 State tract 1,280.60 acres or 12.49% of unit area.							
	Patented Land							
8	Sec.13: All	641.20	6-30-79	I. B. Hadde:	All	Fumarole Ltd.	Fumarole Ltd.:	All
9	Sec.22: Lots 1, 2, 3, 4, S½, NW¼	590.00	2-28-81	J. P. Smith:	All	Fumarole Ltd.	Fumarole Ltd.:	All
10	Sec.34: All	640.00	3-31481	A. G. Quick: P. T. Land:	75% 25%	Hot Rock Co.	Hot Rock Co.:	All
11	Tract 39	80.00	4-30-81	M. V. Jones:	All	Unleased	M. V. Jones:	All
	3 Patented tracts 1,951.20 acres or 19.04% of unit area.							
Total:	11 tracts 10,249.10 acres in entire unit area.							

271.15 Form of collective bond

COLLECTIVE CORPORATE SURETY

Known all men by these presents, That we, _____,
(Name of Unit Operator)
signing as Principal, for and on behalf of the record owners of unitized substances now or hereafter covered by the unit agreement for this _____, approved _____,
(Name of Unit) (Date)
_____, as Surety are jointly and severally held and firmly bound unto the United States of America in the sum of _____ Dollars, lawful money of the United States, for the use and benefit of and to be paid to the United States and any entryman or patentee of any portion of the unitized land, heretofore entered or patented with the reservation of the geothermal resources deposits to the United States, for which payment well and truly to be made, we find ourselves, and each of us, and each of our heirs, executors, administrators, successors, and assigns by these presents.
(Name and address of Surety)
(Amount of bond)

The condition of the foregoing obligation is such that, whereas the Secretary on _____ approved under the provisions of the Geothermal Steam Act of 1970, a unit agreement for the development and operation of the _____;
(Date)
(Name of Unit and State)

and

Whereas said Principal and record owners of unitized substances, pursuant to said unit agreement, have entered into certain covenants and agreements as set forth therein, under which operations are to be conducted; and

Whereas said Principal as Unit Operator has assumed the duties and obligations of the respective owners of unitized substances as defined in said unit agreement; and

Whereas said Principal and surety agree to remain bound in the full amount of the bond for failure to comply with the terms of the unit agreement, and the payment of rentals, minimum royalties, and royalties due under the Federal leases committed to said unit agreement; and

Whereas the Surety hereby waives any right of notice of and agrees that this bond may remain in force and effect notwithstanding:

(a) Any additions to or change in the ownership of the unitized substances herein described.

(b) Any suspension of the drilling or producing requiremens or waiver, suspension or reduction of rental or minimum royalty payments or reduction of royalties pursuant to applicable laws or regulations thereunder; and

Whereas said Principal and Surety agree to the payment of conpensatory royalty under the regulations of the Interior Department in lieu of drilling necessary offset wells in the event of drainage; and

Whereas nothing herein contained shall preclude the United States from requiring an additional bond at any time when deemed necessary:

Now, therefore, if the said Principal shall faithfully comply with all of the provisions of the above-identified unit agreement and with the terms of the leases committed thereto, then the above

obligation is to be of no effect; otherwise to remain in full force and virtue.

Signed, sealed, and delivered this _____ day of _____, 19___, in the presence of:

Witnesses:

_____ _____
(Principal)

_____

_____ _____
(Surety)

_____

271.16 Form of designation of successor unit operator by working interest owners.

Designation of successor Unit Operator _____,
Unit Area, County of _____ State of _____,
No._____.

This indenture, dated as of the _____day of_____,
19___, by and between _____ hereinafter designated
as "First Party," and the owners of unitized working interest, hereinafter
designated as "Second Parties,"

Witnesseth: Whereas under the provisions of the Geothermal
Steam Act of December 24, 1970, 84 Stat. 1566, the Secretary
on the _____day of _____, 19___, approved
a unit agreement for the _____Unit Area, wherein
_____ is designated as Unit Operator; and

Whereas said_____ has resigned as such
Operator,[1] and the designation of a successor Unit Operator is now
required pursuant to the terms thereof; and

Whereas First Party has been and hereby is designated by Second
Parties as Unit Operator, and said First Party desires to assume all
the rights, duties, and obligations of Unit Operator under the said
unit agreement.

Now, therefore, in consideration of the premises hereinbefore
set forth and the promises hereinafter stated, the First Party hereby
covenants and agrees to fulfill the duties and assume the obligations
of Unit Operator under and pursuant to all the terms of the
_____unit agreement, and the Second Parties covenant

[1] Where the designation of a successor Unit Operator is required for any reason other than resignation, such reason shall be substituted for the one stated.

and agree that, effective upon approval of this idenure by the Supervisor, of the Geological Survey, First Party shall be granted the exclusive right and privilege of exercising any and all rights and privileges and Unit Operator, pursuant to the terms and conditions of said unit agreement;said unit agreement being hereby incorporated herein by references and made a part hereof as fully and effectively as though said unit agreement were expressly set forth in this instrument.

In witness whereof, the parties hereto have executed this instrument as of the date hereinabove set forth.

_____ _____
(First Party)

_____
(Witnesses)

_____ _____
(Second Party)

_____
(Witnesses)

I hereby approve the foregoing indenture designating _____as Unit Operator under the unit agreement for the _____Unit Area, this _____day of _____, 19___.

_____
Supervisor, United States Geological Survey

271.17 Form of change in unit operator by assignment.

Change in Unit Operator_____unit Area,

County of_____, State of_____,

No._____.

This indenture, dated as of the _____day of _____,

19___, by and between _____hereinafter designated

as "First Party," and_____,hereinafter designated

as "Second Party."

Witnesseth: Whereas under the provisions of the Geothermal Steam Act of December 24, 1972, 84 Stat. 1566, the Secretary on the _____day of _____, 19___, approved a unit agreement for the _____Unit Area, wherein the First Party is designated as Unit Operator; and

Whereas the First Party desires to transfer, assign, release, and quitclaim, and the Second Party desires to assume all the rights, duties, and obligations of Unit Operator under the unit agreement; and

Whereas for sufficient and valuable consideration, the receipt whereof is hereby acknowledged, the First Party has transferred, conveyed and assigned all his/its rights under certain operating agreements involving lands within the area set forth in said unit agreement unto the Second Party:

Now, therefore, in consideration of the premises hereinbefore set forth, the First Party does hereby transfer, assign, release, and quitclaim unto Second Party all of First Party's rights,duties and obligations as Unit Operator under said unit agreement; and

Second Party hereby accept this assignment and hereby convenants and agrees to fulfill the duties and assume the obligations of Unit Operator under and pursuant to all the terms of said unit agreement to the full extent set forth in this assignment, effective upon approval of this indenture by the Supervisor of the Geological Survey; said unit agreement being hereby incorporated herein by reference and made a part hereof as fully and effectively as though said unit agreement were expressly set forth in this instrument.

In witness whereof, the parties hereto have executed this instrument as of the date hereinabove set forth.

_____ _____
(First Party)

_____
(Witnesses)

_____ _____
(Second Party)

_____
(Witnesses)

I hereby approve the foregoing indenture designated _____ _____as Unit Operator under the unit agreement for the _____Unit Area, this _____day of _____, 19___.

_____
Supervisor, United States Geological Survey

BUREAU OF LAND MANAGEMENT
Library
Denver Service Center

Form 1279-3
(June 1984)

BORROWER

TD 195 .G4 G452

Supplement to d
environmental

DATE LOANED	BORROWER

USDI -- BLM